4.0 General Risk Levels

Before reviewing the specific study results, it is helpful to review a profile of the regulated hazardous liquid pipelines included in the study. This data is presented below:

Total Length of Regulated Pipelines Included in Study	7,800 Miles
Total Length of Regulated Pipeline within 500' of a Rail Included in Study	2,061 Miles (26.4%)
Total Length of Internal Inspection Piggable Pipeline Included in Study	4,495 Miles (57.6%)
Total Number of Line Sections Included in Study	552 Pipelines
Average Length of Each Section	14.1 Miles
Mean Year of Original Pipe Construction	1957
Mean Diameter of Pipe	12.3 Inches
Mean Diameter of Internal Inspection Piggable Pipe	14.3 Inches
Mean Normal Operating Temperature	97.9°F
Number of Leaks During Study Period	514 Leaks
Average Spill Size	408 Barrels
Median Spill Size	5 Barrels
Average Damage Per Incident (Uninflated)	$141,000
Median Damage Per Incident ($US 1983)	$7,200
Average Age Of Leak Pipe	40.8 Years
Average Diameter of Leak Pipe	10.2 Inches
Mean Normal Operating Temperature of Leak Pipe	109.7°F
Injuries During Study Period	49
Fatalities During Study Period	3

In the table above, the terms mean and average were used to differentiate between the methods used to calculate the values. *Average* values were determined by simple division. For example, the average spill size was determined by dividing the sum of each individual spill volume by the total number of spills. *Mean* values, on the other hand, were determined by *weighting* the individual parameters by pipe length and the number of years of service during the study period. For instance, the mean normal operating temperature was determined as follows:

$$T_{mean} = \Sigma \{T_iL_iY_i + T_{(i+1)}L_{(i+1)}Y_{(i+1)} + \ldots\} \div \Sigma \{L_iY_i + L_{(i+1)}Y_{(i+1)} + \ldots\}$$

where: T_{mean} = mean normal operating temperature
T_i = normal operating temperature for line segment_i
L_i = length of line segment_i
Y_i = number of years of line segment_i operation during study period

We believe that this weighting method provides a much more meaningful representation of mean values for many parameters than simple division. It has been used where appropriate to determine the values shown in many of the tables which follow.

In general, the characteristics presented above for all pipelines do not differ dramatically from those characteristics for pipe where leaks occurred. Generally, pipelines where leaks occurred operated about 10°F hotter than the normal operating temperature for all pipe, and had a diameter roughly 2 inches smaller. The major difference was pipe age; the average age of all pipelines was about 31 years, while that of leak pipe was nearly 41 years.

In terms of distribution, approximately 26 percent of all pipe was within 500 feet of a rail line; as we shall see in a following subsection, a proportional percentage of the leak incidents occurred on these pipe segments. Nearly 60 percent of all pipelines were reported to be internally inspection piggable; 70 percent of the piggable lines were internally inspected during the ten year study period.

4.1 Overall Incident Causes

The overall incident rate for all pipelines included in this study was 7.12 incidents per 1,000 mile years. Table 4-1 presents the detailed data.

As indicated, the leading cause of hazardous liquid pipeline leak incidents from January 1981 through December 1990 was external corrosion, which caused 58.8 percent of all leaks. Another 2.7 percent were caused by internal corrosion. The volumes spilled as a result of both types of corrosion were nominal in size, relative to the spill size resulting from other causes (225 barrels on average for external corrosion leaks and 47 barrels for internal corrosion leaks, versus 723 barrels for other causes).

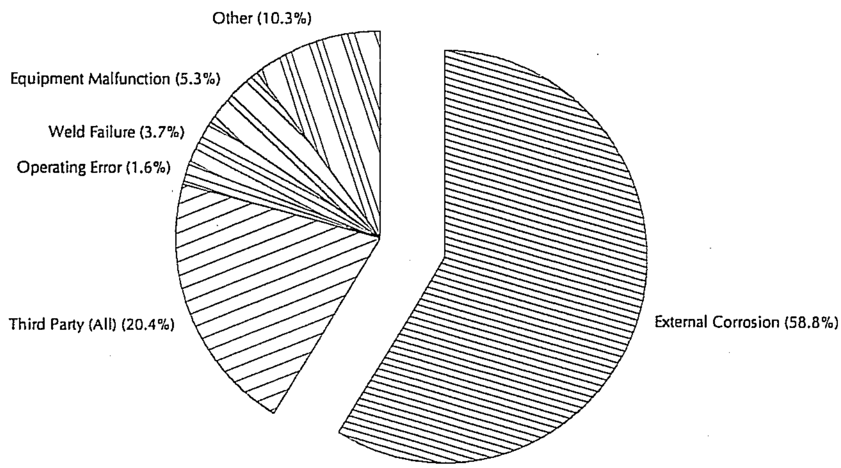
The second leading cause of all leaks was third-party damage. In our data, third party damage was subdivided into five categories:

- third party damage due to farm equipment,
- third party damage due to construction,
- third party damage due to train derailments,
- third party damage which caused coating damage resulting in subsequent external corrosion leaks, and
- third party damage due to other causes.

Table 4-1
Overall Incident Causes
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	No. of Incidents	Incident Rate	Percentage
External Corrosion	302	4.18	58.75%
Internal Corrosion	14	0.19	2.72%
3rd Party - Construction	64	0.89	12.45%
3rd Party Farm Equipment	18	0.25	3.50%
3rd Party - Train Derailment	2	0.03	0.39%
3rd Party - External Corrosion	7	0.10	1.36%
3rd Party - Other	14	0.19	2.72%
Human Operating Error	8	0.11	1.56%
Design Flaw	2	0.03	0.39%
Equipment Malfunction	27	0.37	5.25%
Maintenance	5	0.07	0.97%
Weld Failure	19	0.26	3.70%
Other	25	0.35	4.86%
Unknown	7	0.10	1.36%
Total	514	7.12	100.00%
Number of Mile Years	72,181		
Mean Year Pipe Constructed	1957		
Mean Operating Temperature (°F)	97.9		
Mean Diameter (inches)	12.3		
Average Spill Size (barrels)	408		
Average Damage ($US 1983)	141,477		

Incident Cause Distribution



All types of third party damage combined, were responsible for causing 20.4% of all leak incidents during our 10 year study period. Of these, construction activity was by far the major culprit, causing 12.5% of all leaks.

Spills resulting from third-party damage due to farm equipment were large, averaging over 1,600 barrels. Additionally, the largest quantity of fluid spilled occurred from the two leaks caused by train derailment; the two leaks in this category evidence a considerably large average spill size of 4,762 barrels of fluid.

A total of 46 leaks occurred due to equipment malfunction or weld failure. 5.3% of all leaks were caused by equipment malfunction while 3.7 percent of all leaks were attributable to weld failure. Spill sizes for these leaks averaged about 700 barrels of fluid.

The number of leaks that occurred because of human error, design flaw in pipe construction or poor maintenance procedures were nominal, together comprising less than three percent of all leaks. Despite the low frequency of leaks due to human operating error, the size of spill occurring as a result of these leaks is very large, averaging 3,102 barrels. This spill size is the second largest average spill size resulting from any cause. Leaks caused by poor maintenance, on the other hand, resulted in the lowest spill size, with an average of only 3.2 barrels.

4.2 Interstate versus Intrastate Pipelines

The data collected permited a categorization of pipeline units by interstate lines and intrastate lines. Approximately 28 percent of the regulated hazardous liquid pipelines within the state of California are interstate lines. A summary profile of these pipelines is shown below.

Description	Interstate Pipelines	Intrastate Pipelines
Total Number of Line Sections	71 Sections (12.9%)	480 Sections (87.1%)
Total Length of Pipelines	2,141 Miles (27.5%)	5,646 Miles (72.5%)
Total Length Within 500 feet of a Rail Line	819 Miles (38.3% of Interstate)	1,242 Miles (22.0% of Intrastate)
Total Length of Internal Inspection Piggable Pipe	1,970 Miles (92.0% of Interstate)	2,513 Miles (44.5% of Intrastate)
Average Length of Section	30.2 Miles	11.8 Miles
Mean Year of Original Pipe Construction	1966	1953
Mean Diameter of Pipe	16.7 Inches	10.7 Inches

Mean Diameter of Internal Inspection Piggable Pipe	17.6 Inches	12.1 Inches
Mean Normal Operating Temperature	77.3°F	106.1°F
Mean Normal Operating Pressure	1,033 psig	688 psig
Average Valve Spacing	9.92 Miles	6.58 Miles
Average Hydrostatic Test Interval	6.27 Years	4.51 Years
Number of Leaks During Study Period	48 Incidents	459 Incidents

Table 4-2 presents a comparison of the leak incident rates for interstate versus intrastate pipelines. Comparing these results we find that the leak incident rate for intrastate lines was significantly higher per 1,000 mile years than the incident rate for interstate pipelines: 8.45 in contrast to 2.69 leaks per 1000 mile years.

There are several possible explanations for the roughly three-fold difference between the interstate and intrastate pipeline incident rates. We believe that the following items had the greatest impact, as we will examine in later subsections of this report.

- The mean interstate pipeline was 13 years newer than the intrastate pipelines.

- The mean normal operating temperature was nearly ambient for interstate pipelines, almost 30°F less than for intrastate lines.

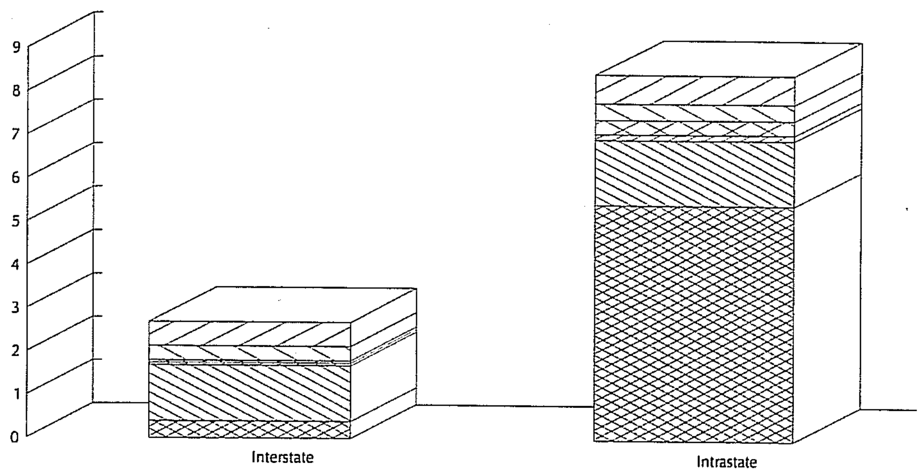
- The mean normal pipe diameter was almost 17" for interstate lines, over 50% greater than for intrastate lines.

As demonstrated in Table 4-2, the majority of the incident rate difference occurred in the incident rate for leaks caused by external corrosion. Also, the average spill size and average damage was considerable greater for the larger mean diameter interstate pipelines.

Table 4-2
Interstate versus Intrastate Pipelines
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Interstate		Intrastate	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	7	0.39	295	5.43
Internal Corrosion	0	0.00	14	0.26
3rd Party - Construction	14	0.78	50	0.92
3rd Party Farm Equipment	1	0.06	17	0.31
3rd Party - Train Derailment	2	0.11	0	0.00
3rd Party - External Corrosion	1	0.06	6	0.11
3rd Party - Other	5	0.28	9	0.17
Human Operating Error	1	0.06	7	0.13
Design Flaw	1	0.06	1	0.02
Equipment Malfunction	6	0.34	21	0.39
Maintenance	2	0.11	3	0.06
Weld Failure	1	0.06	18	0.33
Other	7	0.39	18	0.33
Total	48	2.69	459	8.45
Number of Mile Years	17,838		54,343	
Mean Year Pipe Constructed	1966		1953	
Mean Operating Temperature (°F)	77.3		106.1	
Mean Diameter (inches)	16.7		10.7	
Average Spill Size (barrels)	514		399	
Average Damage ($US 1983)	892,762		65,206	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The average valve spacing was also worth noting. The average valve spacing on interstate pipelines was 9.92 miles, 51% greater than for intrastate lines. In addition, interstate lines had a mean pipe diameter which was 50% greater than for intrastate lines. If we assume an average wall thickness of 0.25" for all lines, the mean fluid contents per mile for interstate and intrastate pipelines can be calculated to be 1,344 and 535 barrels per mile respectively. After correcting for the difference in mean pipe diameter and average valve spacing, one would expect the average spill volume for interstate lines to be 3.8 times that for intrastate lines, assuming valve spacing had a direct relationship with spill volume. However, the average spill volume for interstate lines was only 29% greater than for intrastate lines, 351% less than one may have expected. Obviously, other factors significantly affect spill volumes, as we shall review in a later section.

4.3 Common Carrier versus Non-Common Carrier Lines

Analyses similar to those for interstate versus intrastate pipeline have been performed for common carrier (those transporting freight for hire) versus non-common carrier lines. Approximately 25 percent of the regulated hazardous liquid pipelines within the State of California were common carrier lines. A summary profile of these pipelines has been presented below.

Description	Common Carrier Pipelines	Non-Common Carrier Pipelines
Total Number of Line Sections	135 Sections (24.5%)	416 Sections (75.5%)
Total Length of Line Sections	3,602 Miles (46.3%)	4,186 Miles (53.7%)
Total Length Within 500 feet of a Rail Line	1,452 Miles (40.3% of Common Carrier Pipelines)	609 Miles (14.5% of Non-Common Carrier Pipelines)
Total Length of Internal Inspection Piggable Pipe	2,831 Miles (78.6% of Common Carrier Pipelines)	1,652 Miles (39.5% of Non-Common Carrier Pipelines)
Average Length of Section	26.7 Miles	10.1 Miles
Mean Year of Original Pipe Construction	1964	1951
Mean Diameter of Pipe	13.9 Inches	11.0 Inches
Mean Diameter of Internal Inspection Piggable Pipe	15.2 Inches	13.1 Inches
Mean Normal Operating Temperature	81.1°F	112.3°F
Mean Normal Operating Pressure	933 psig	664 psig

Average Valve Spacing	10.14 Miles	5.32 Miles
Average Hydrostatic Test Interval	5.88 Years	4.38 Years
Number of Leaks During Study Period	104	403

Tables 4-3 presents a comparison of the leak incident rates for common carrier versus non-common carrier pipelines. Comparing these results we find that the leak incident rate for non-common carrier lines was roughly three times greater than for common carrier pipelines: 9.88 in contrast to 3.31 incidents per 1,000 mile years. Once again, nearly all of the incident rate difference occurred in the rate for leaks caused by external corrosion.

The differences between these line sections were very similar to those for interstate and intrastate pipelines discussed in the prior subsection. We believe that the following items had the greatest impact on the differences between common carrier and non-common carrier leak incident rates. (Each of these parameters will be examined individually in subsequent subsections of this report.)

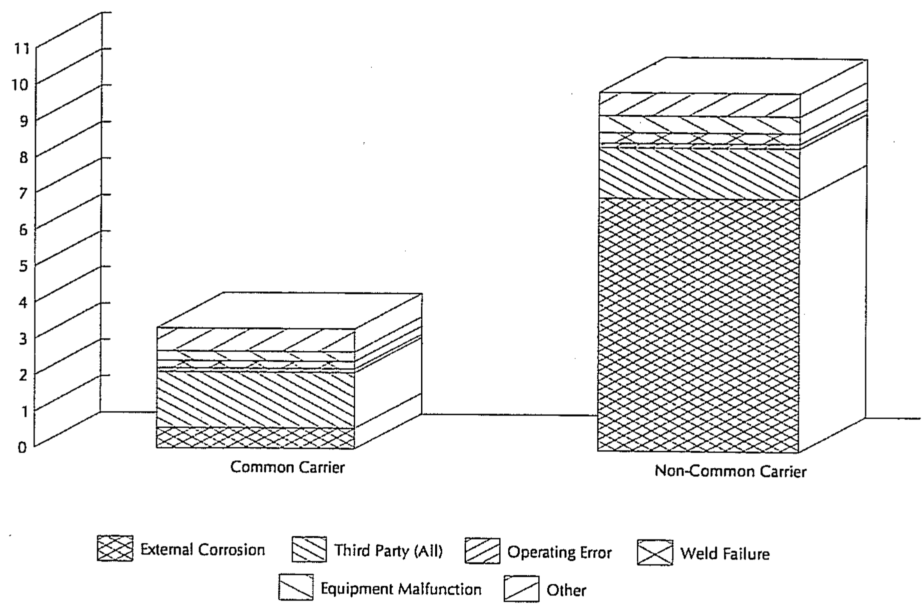
- The mean common carrier line was 13 years newer than the non-common carrier pipeline.
- The mean normal operating temperature was 31°F less than for common carrier lines than it is for non-common carrier pipelines.
- The mean normal pipe diameter was almost 14" for common carrier lines, over 25% greater than non-common carrier lines.

The average valve spacing differences were also very similar to those for interstate and intrastate pipelines. The average valve spacing on common carrier pipelines was 10.14 miles, 91% greater than for non-common carrier lines. In addition, common carrier lines had a mean pipe diameter which was 26% greater than for non-common carrier lines. If we assume an average wall thickness of 0.25" for all lines, the mean fluid contents per mile for common carrier and non-common carrier pipelines can be calculated to be 925 and 567 barrels per mile respectively. After correcting for the difference in mean pipe diameter and average valve spacing, one would expect the average spill volume for common carrier lines to be 2.5 times that for non-common carrier lines, assuming valve spacing had a direct relationship with spill volume. However, the average spill volume for common carrier lines was only 25% greater than for non-common carrier lines, 225% less than one may have expected.

Table 4-3
Common Carrier versus Non-Common Carrier Pipelines Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Common Carrier		Non-Common Carrier	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	18	0.57	284	6.96
Internal Corrosion	3	0.10	11	0.27
3rd Party - Construction	30	0.96	34	0.83
3rd Party Farm Equipment	6	0.19	12	0.29
3rd Party - Train Derailment	2	0.06	0	0.00
3rd Party - External Corrosion	1	0.03	6	0.15
3rd Party - Other	9	0.29	5	0.12
Human Operating Error	3	0.10	5	0.12
Design Flaw	2	0.06	0	0.00
Equipment Malfunction	8	0.25	19	0.47
Maintenance	4	0.13	1	0.02
Weld Failure	7	0.22	12	0.29
Other	11	0.35	14	0.34
Total	104	3.31	403	9.88
Number of Mile Years	31,385		40,796	
Mean Year Pipe Constructed	1964		1951	
Mean Operating Temperature (°F)	81.1		112.3	
Mean Diameter (inches)	13.9		11.0	
Average Spill Size (barrels)	484		387	
Average Damage ($US 1983)	396,163		61,050	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



4.4 Incident Rates By Pipeline Contents

The incident rates differed by the type of fluid transported. Table 4-4 details incident rates by cause and pipeline contents. The incident rate for crude oil pipelines (comprising 43.4% of the total mile years of operation during the study period) was 9.89 incidents per 1,000 mile years. This was more than double the rate for product pipelines which represented 50.4% of the mile years of operation during the study period. (Product pipelines included those which transport gasolines, diesel, jet fuel, etc.)

The vast majority of this difference was external corrosion. A regression analysis was performed to review the effect of pipe contents, specifically crude oil, on the probability of a leak. The analysis included the following variables, as well as a dummy indicator for whether or not the line carried crude oil:

- total length of pipeline section,
- year of pipe construction,
- normal operating temperature,
- normal operating pressure, and
- normal operating flow rate.

We found that by controlling for factors such as year of construction, operating temperature and other pertinent variables, the relationship disappeared between crude oil transportation and the probability of a leak, for those leaks caused by factors other than external corrosion. *Crude oil, however, was a statistically significant determinant that strongly raised the probability of a leak occurring because of external corrosion.* As we will examine in a later subsection, this was largely a result of operating temperature. As indicated in Table 4-4, the mean operating temperature for crude oil lines was 109°F, versus 86°F for product lines.

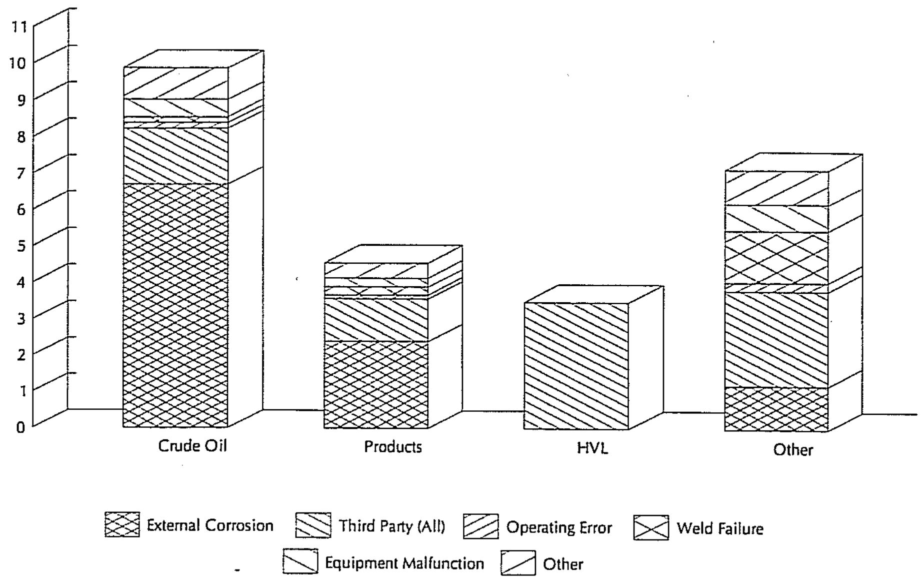
It was also interesting to note that all of the injuries and fatalities occurred on product pipelines. In addition, the average damage per incident was $363,000 for product lines (constant $US 1983), almost four times that for crude oil pipelines. Based on the pipe diameter differences between crude and product pipelines, one would expect average crude oil spills to be twice the size of those for product lines, all other things being equal. However, the data indicates that the average crude oil spill volume was only 42% greater than for product lines. Fluid viscosity may help explain this discrepancy. The more viscous crude oil would take much longer to drain from a severed line than petroleum products, which would tend to reduce crude oil spill volumes.

The number of leaks and total mile years of operation during the study period for highly volatile liquid (HVL) and "other" lines was relatively small. The reader should be cautioned against making anything but very general conclusions using the results of this small data base.

Table 4-4
Incidents By Pipeline Contents
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Crude Oil		Products		HVL		Other	
	Number	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	210	6.70	87	2.39	0	0.00	5	1.19
Internal Corrosion	10	0.32	1	0.03	0	0.00	3	0.72
3rd Party - Construction	28	0.89	28	0.77	1	3.48	7	1.67
3rd Party Farm Equipment	14	0.45	1	0.03	0	0.00	3	0.72
3rd Party - Train Derailment	0	0.00	2	0.05	0	0.00	0	0.00
3rd Party - External Corrosion	2	0.06	4	0.11	0	0.00	1	0.24
3rd Party - Other	4	0.13	8	0.22	0	0.00	0	0.00
Human Operating Error	5	0.16	4	0.11	0	0.00	1	0.24
Design Flaw	2	0.06	0	0.00	0	0.00	0	0.00
Equipment Malfunction	15	0.48	9	0.25	0	0.00	3	0.72
Maintenance	2	0.06	2	0.05	0	0.00	1	0.24
Weld Failure	5	0.16	8	0.22	0	0.00	6	1:43
Other	13	0.41	12	0.33	0	0.00	0	0.00
Total	310	9.89	166	4.55	1	3.48	30	7.15
Number of Mile Years	31,350		36,473		287		4,193	
Percentage of Total Mile Years	43.4%		50.4%		0.4%		5.8%	
Injuries Per 1,000 Mile Years	0	0.00000	49	1.34345	0	0.00000	0	0.00000
Fatalities Per 1,000 Mile Years	0	0.00000	3	0.08225	0	0.00000	0	0.00000
Mean Year Pipe Constructed	1956		1960		1960		1944	
Mean Operating Temperature (°F)	109		86		73		120	
Mean Diameter (inches)	14.6		10.4		6.5		12.2	
Average Spill Size (barrels)	475		335		30		106	
Average Damage ($US 1983)	96,475		363,073		0		20,368	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



4.5 Incident Rates By Study Year

Varying leak incident rates were observed during the ten year study period. Table 4-5 shows the incident rate break-down for each year during the survey period by cause.

The results demonstrate a slight decline over the ten year period: during the first five years the average incident rate was 8.5; during the latter half the average incident rate was 6.9 leaks per 1,000 mile years. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of this overall leak data by year. It showed that the overall incident rate decreased 0.52 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* for this regression was 0.39. (*R squared* values range from zero to one. They can be interpreted as the proportion of the variation in a given sample which can be explained by the resulting linear equation; they are a comparison of the estimated systematic model with the mean of the observed values.)

A similar regression was performed for external corrosion leaks only during the ten year study period. It indicated that the incident rate for external corrosion leaks was decreasing at the rate of 0.21 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.24.

The decreasing trend in incident rates is especially noteworthy considering the fact that all leak data was gathered at the end of the study period. With the increasing trend towards total leak reporting and recording, one would assume that the more recent data collected from a pipeline operator may be more complete than data regarding leaks which occurred several years ago. This would tend to result in relatively lower incident rates for early study years and a corresponding increasing incident rate trend. However, as discussed earlier, the data indicated a rather significant *decreasing* incident rate trend. This indicates two things: first, it indicates that the data gathered must be relatively complete during the earlier years of the study; secondly, it indicates that if any incomplete record keeping did occur during the early years of the study period, the actual rate of decreasing incident rates was higher than indicated by the regressions.

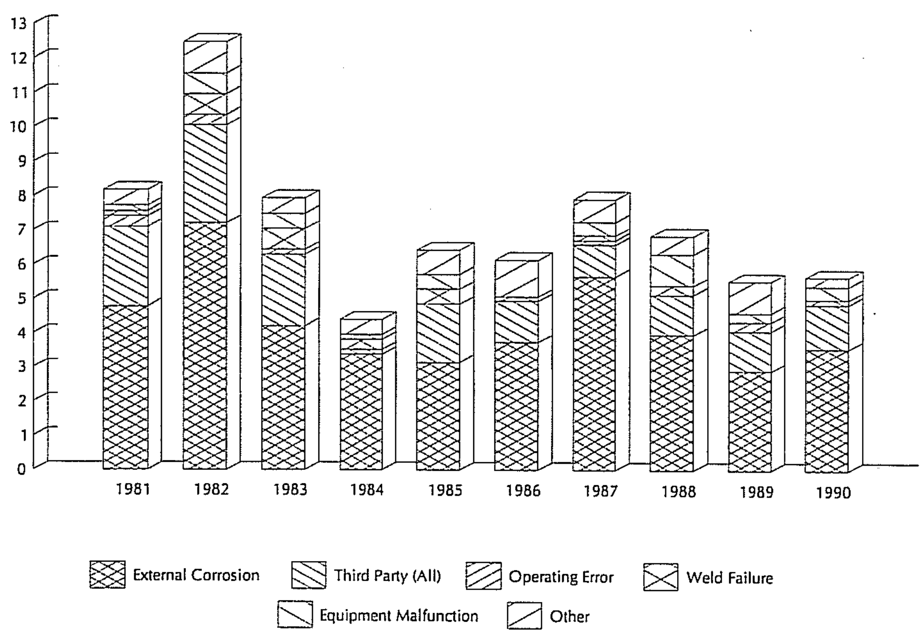
A third regression was performed for leaks caused by all causes except external corrosion during the ten year study period. It indicated that the incident rate for these leaks was decreasing at the rate of 0.19 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.26.

The average spill volumes varied widely during the ten year study period. An ordinary least squares line of best fit was determined to analyze any trend in this data. It indicated a 33.6 barrel per year reduction in average spill size, with an *R squared* of only 0.16.

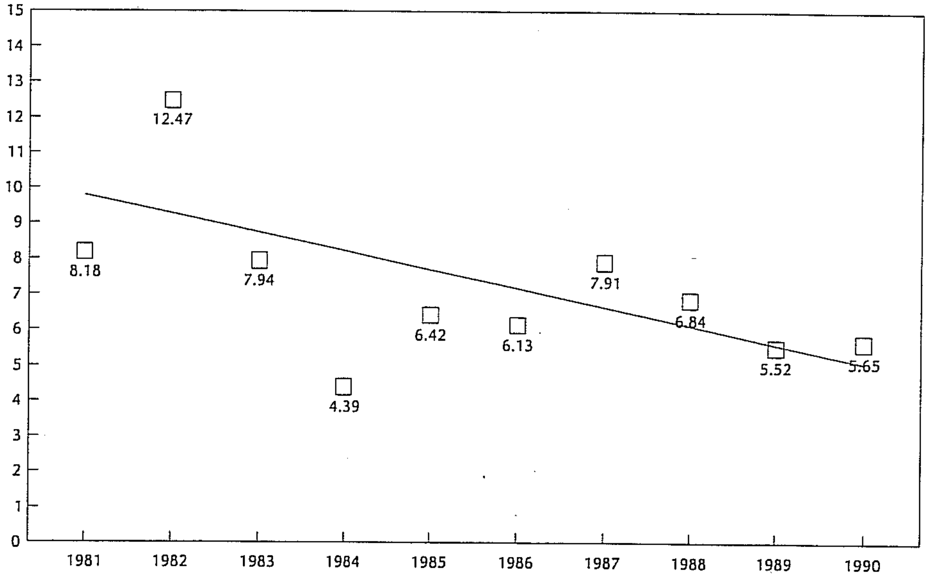
Table 4-5
Incident Rates By Year Of Study
(Incidents Per 1,000 Mile-Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
External Corrosion	4.78	7.21	4.19	3.36	3.14	3.73	5.67	3.95	2.89	3.55
Internal Corrosion	0.00	0.45	0.30	0.15	0.14	0.40	0.53	0.00	0.00	0.00
3rd Party - Construction	1.08	2.40	0.60	0.15	1.43	0.67	0.66	0.79	0.79	0.53
3rd Party - Farm Equipment	1.08	0.15	0.90	0.00	0.00	0.13	0.13	0.13	0.13	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.00	0.14	0.00	0.13	0.00	0.00	0.66
3rd Party - Other	0.15	0.30	0.60	0.00	0.14	0.40	0.00	0.13	0.13	0.13
Human Operating Error	0.31	0.30	0.15	0.00	0.00	0.00	0.13	0.00	0.26	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.13
Equipment Malfunction	0.15	0.60	0.45	0.15	0.43	0.00	0.40	0.92	0.26	0.39
Maintenance	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.39	0.00
Weld Failure	0.15	0.60	0.60	0.29	0.43	0.13	0.13	0.26	0.00	0.13
Other	0.46	0.45	0.15	0.29	0.29	0.67	0.13	0.39	0.53	0.13
Total	8.18	12.47	7.94	4.39	6.42	6.13	7.91	6.84	5.52	5.65
Number of Mile Years	6,482	6,658	6,675	6,835	7,005	7,501	7,587	7,600	7,609	7,610
Mean Year Pipe Constructed	1952	1953	1953	1954	1954	1956	1957	1957	1957	1957
Mean Operating Temperature (°F)	97.0	97.4	97.4	96.8	98.4	97.9	98.0	97.9	98.0	98.0
Mean Diameter (inches)	10.8	10.9	10.9	10.9	11.1	12.3	12.3	12.4	12.4	12.4
Average Spill Size (barrels)	285.0	514.7	889.3	83.6	562.9	609.4	266.6	136.2	377.5	127.4
Average Damage ($1,000 US 1983)	11.0	26.5	92.8	25.6	94.4	171.9	21.4	60.7	651.2	141.4

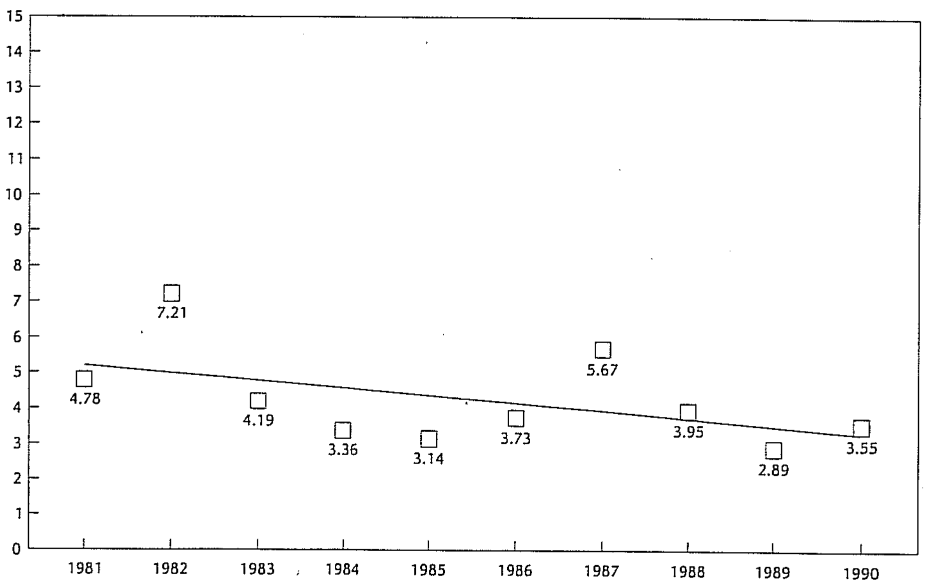
Incident Rates By Year of Study
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

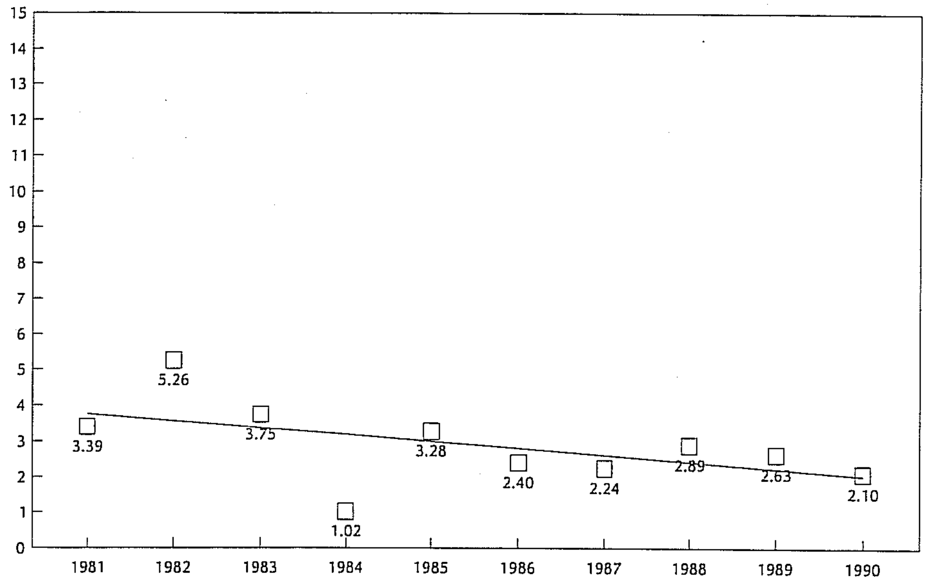


Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Decade of Construction
Incidents Per 1,000 Mile Years

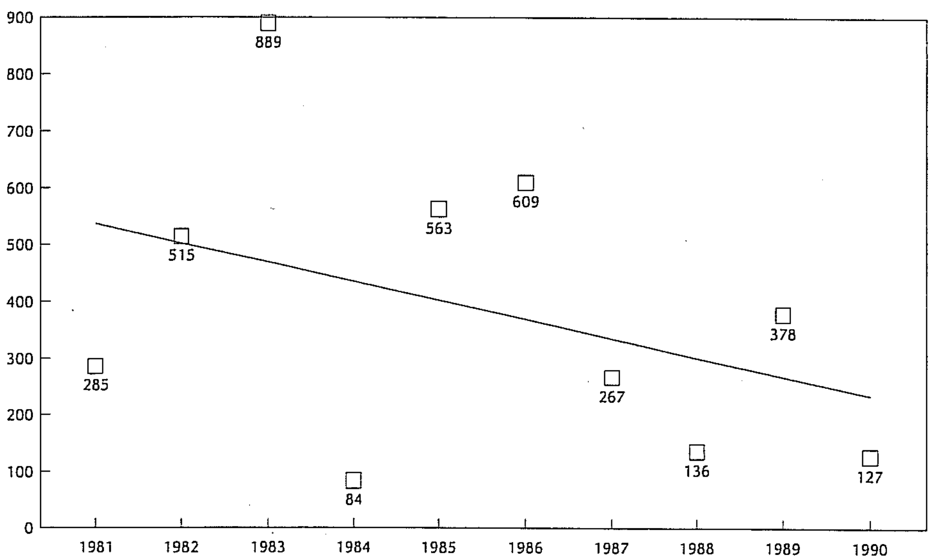


Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Year of Study
Excludes All External Corrosion Incidents

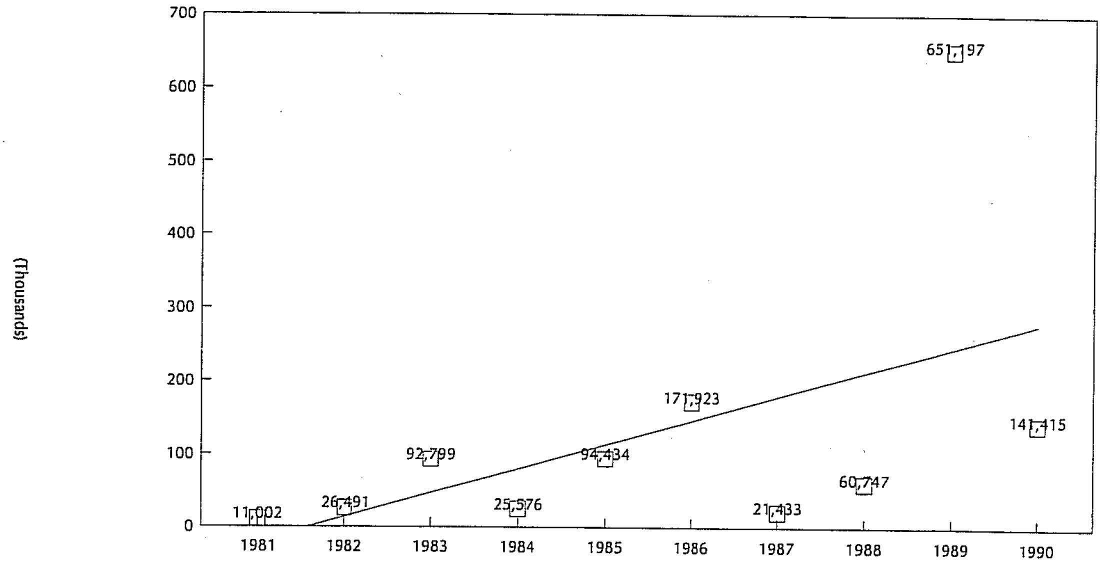
Incidents Per 1,000 Mile Years



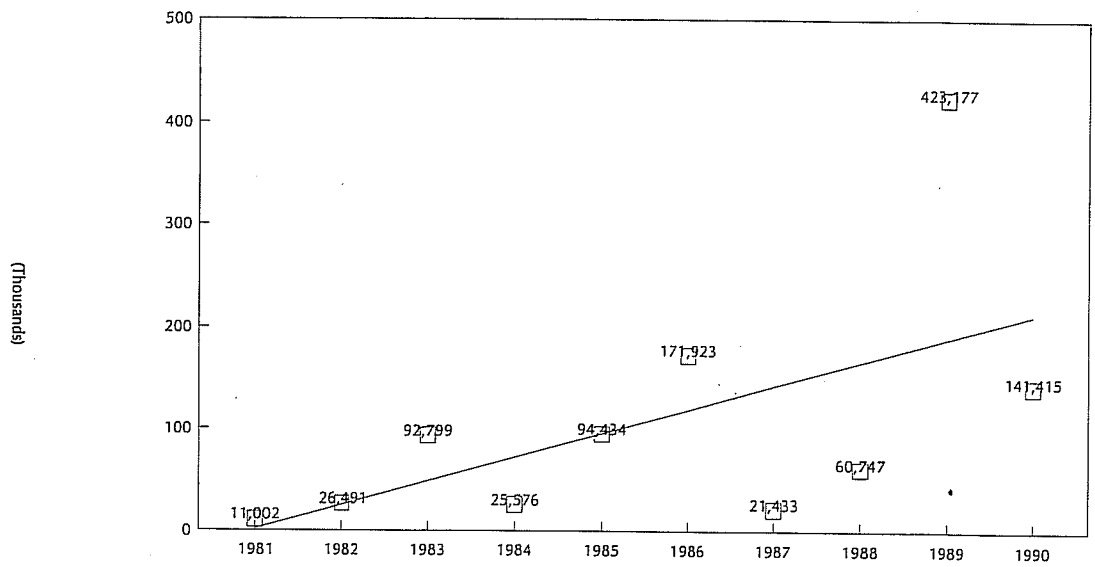
Ordinary Least Squares Line of Best Fit
Average Annual Spill Size (Barrels)



Ordinary Least Squares Line of Best Fit
Average Cost of Damage
$US 1983 - 1,000's



Ordinary Least Squares Line of Best Fit
Average Cost of Damage - Excluding 1989 Train Derailment Incident
$US 1983 - 1,000's



Finally, ordinary least squares lines of best fit were determined for the average cost of damage per incident during the ten year study period. Prior to running the regressions, all cost data was normalized to constant 1983 US dollars. Using all incidents during the study period yielded a $33,040 ($US 1983) per year increase in average spill cost, with an *R squared* of 0.27. After deleting the 1989 San Bernardino train derailment, the regression indicated a $23,366 ($US 1983) per year increase in average spill cost, with an *R squared* of 0.33.

4.6 Railroad Effect

As discussed earlier, one of the major inspirations behind this research effort was the 1989 San Bernardino train derailment. Our analyses directly addressed the relationship between train derailments and pipeline leaks. Of all of the hazardous liquid pipelines included in the study, 2,061 miles (26.4%) were located within 500 feet of a rail line; the remaining 5,742 miles (73.6%) were further away from any rail lines.

The data clearly evidence a lack of correlation between proximity to a rail line and any increased incidence of pipeline leaks. As depicted in Table 4-6, the incident rate for leaks occurring on all hazardous liquid pipelines within 500 feet of a rail line was actually 0.17 incidents per 1,000 mile years less than the rate observed for other pipe. Specifically, the overall incident rate was 6.79 incidents per 1,000 mile years for pipe within 500 feet of a rail line, versus 6.96 incidents per 1,000 mile years for other pipe.

As mentioned in Section 2.10 earlier, the length of pipeline within 500' of a rail line was resolved to within 1.7% by comparing EDM Services' mapped information with that provided by the pipeline operators. As a result, all data presented in this section regarding incident rates associated with rail lines has an inherent 1.7% uncertainty.

The two pipeline leaks which were caused by train derailments during the study period resulted in a leak incident rate for this cause of only 0.03 incidents per 1,000 mile years. It should also be noted that both of these leaks were actually caused by damage from clean up equipment, not the derailment itself.

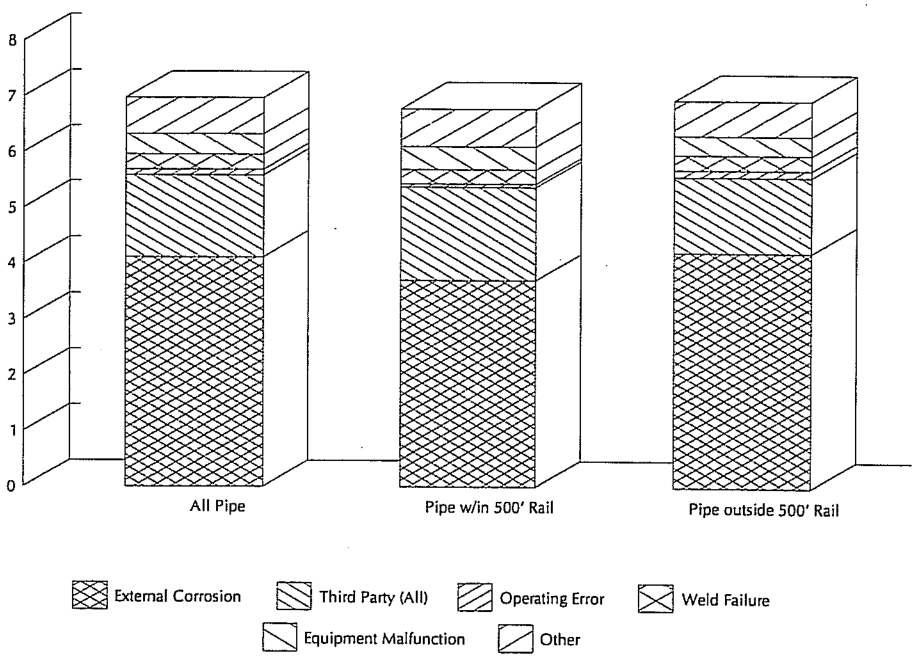
This high level of safety is remarkable, since 1,990 train derailments were reported to the Public Utilities Commission during the study period. Although we do not know how many of these occurred near regulated hazardous liquid pipelines, one can conclude that the likelihood of a derailment resulting in pipeline rupture is extremely remote. Further, the frequency of train derailment caused leak incidents is the lowest of any cause included in the study.

The average spill size of leaks occurring within 500 feet of a rail line is roughly one third the average spill size for other lines. This is especially noteworthy considering the relatively large derailment caused spills.

Table 4-6
Railroad Effect
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	All Pipe		Pipe w/in 500' Rail		Pipe outside 500' Rail	
	Total No.	Rate	Number	Rate	Number	Rate
External Corrosion	298	4.12	71	3.71	227	4.22
Internal Corrosion	14	0.19	3	0.16	11	0.20
3rd Party - Construction	64	0.89	21	1.10	43	0.80
3rd Party Farm Equipment	18	0.25	0	0.00	18	0.33
3rd Party - Train Derailment	2	0.03	2	0.10	0	0.00
3rd Party - External Corrosion	7	0.10	3	0.16	4	0.07
3rd Party - Other	14	0.19	6	0.31	8	0.15
Human Operating Error	8	0.11	1	0.05	7	0.13
Design Flaw	2	0.03	0	0.00	2	0.04
Equipment Malfunction	27	0.37	8	0.42	19	0.35
Maintenance	5	0.07	2	0.10	3	0.06
Weld Failure	19	0.26	5	0.26	14	0.26
Other	26	0.36	8	0.42	18	0.33
Total	504	6.97	130	6.79	374	6.96
Number of Mile Years	72,303		19,150		53,771	
Average Spill Size (barrels)			288		452	
Average Damage ($US 1983)			363,732		92,689	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The average damage was much larger for leak incidents near rail lines: $363,732 ($US 1983) per incident versus $92,689 for other incidents.

4.7 Standard Metropolitan Statistical Areas (SMSA's)

One of the objectives of our study was to determine whether or not pipe within standard metropolitan statistical areas (SMSA) had a significantly different leak incident rate than pipelines outside SMSA's. For this purpose a substantial amount of time was spent by EDM office personnel explicitly mapping the locations of all regulated hazardous liquid pipelines within the state. This was done by measuring the length of line off of the Thomas Guide map book overlays as described earlier in Section 2.4. As a data verification check, the total length of line measured from the Thomas Guide overlays was compared to the total pipeline lengths furnished from the pipeline operators. These two figures were resolved to within 0.92 miles, or 0.01% of each other. (The actual length of pipe within each County will be presented later in Table 5-2A, along with other data.)

Table 4-7 presents the results of our work. Nearly 74% (5,827 miles) of California's hazardous liquid pipe was within SMSA county lines, while the remaining 2,084 miles of pipe were outside SMSA's. The leak rates observed within SMSA's were over three times higher than those observed outside of SMSA's, 7.84 versus 2.49 incidents per 1,000 mile years.

One hypothesis for the higher incident rate for pipelines within SMSA's was that since SMSA's contained zones which were densely populated, heavy third party activity could result in a higher frequency of accidental pipeline rupture. Indeed, the combined incident rate for third party activity was nearly twice as high in SMSA's than it was outside SMSA's, 1.51 versus 0.81 incidents per 1,000 mile years.

However, the vast majority of the difference between SMSA and non-SMSA leak incident rates resulted from external corrosion. Within SMSA's, we observed a rate of 4.86 incidents per 1,000 mile years; outside SMSA's the external corrosion incident rate was only 1.01 incidents per 1,000 mile years, roughly one-fifth the value for pipe within SMSA's. Although the data collected did not allow us to specifically analyze the reasons for this difference, there are several possible explanations:

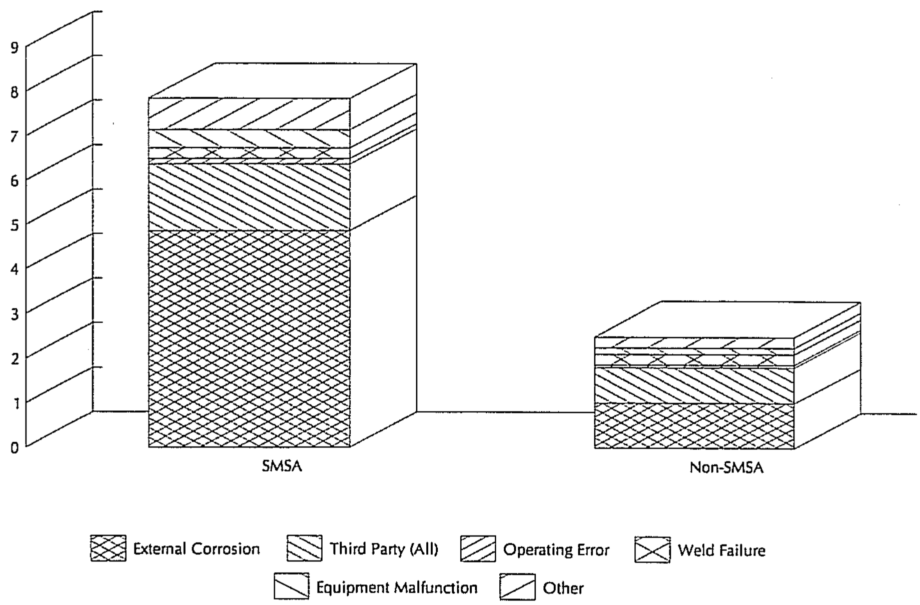
- Pipelines in densely populated areas are likely to be subjected to cathodic protection system interference from other nearby substructures.

- Pipelines buried beneath paved streets are more difficult or impossible to access for specialized cathodic protection surveys (e.g. close interval surveys) to identify locations with marginal or inadequate protection.

Table 4-7
Standard Metropolitan Statistical Areas (SMSA) Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	SMSA		Non-SMSA	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	283	4.86	21	1.01
Internal Corrosion	14	0.24	0	0.00
3rd Party - Construction	56	0.96	9	0.43
3rd Party Farm Equipment	14	0.24	3	0.14
3rd Party - Train Derailment	0	0.00	2	0.10
3rd Party - External Corrosion	7	0.12	0	0.00
3rd Party - Other	11	0.19	3	0.14
Human Operating Error	7	0.12	1	0.05
Design Flaw	1	0.02	1	0.05
Equipment Malfunction	24	0.41	3	0.14
Maintenance	5	0.09	0	0.00
Weld Failure	14	0.24	5	0.24
Other	21	0.36	4	0.19
Total	457	7.84	52	2.49
Number of Mile Years	58,277		20,844	
Average Spill Size (barrels)	331		1,049	
Average Damage ($US 1983)	96,807		395,326	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



- The cost of replacing pipe sections in urban areas is generally much higher than it is for rural areas, especially for pipe within roadways. This relatively high replacement cost may cause many operators to defer replacements in these areas.

- It is often extremely difficult, and sometimes nearly impossible, to secure the permits required to construct new lines or replace pipelines with high leak-history in urban areas, even though this work would reduce the risk to the public.

4.8 Decade of Construction Effects

Pipe age had a definite effect on the leak incident rates. Table 4-8 shows the variation in leak incident rates by decade of pipe construction. As indicated, pipe construction before 1940 (1926 mean year of construction) had a leak incident rate nearly twenty times that of pipe constructed in the 1980's. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of the overall leak data by year of pipe construction. It indicated that the overall leak incident rate decreased 0.286 incidents per year per 1,000 mile years. The resulting *R squared* for this regression was 0.82. A second regression was performed which excluded all pipe installed prior to 1940. This regression indicated an overall leak incident rate reduction of 0.147 incidents per year per 1,000 mile years, with an *R squared* of 0.86.

Once again, we found that the vast majority of the difference in leak incident rates occurred because of variations in external corrosion rates. Some of the reasons for this variation may have included:

- The extent of external corrosion is generally considered a function of time. In general, the more time a given portion of pipe is allowed to corrode, the more likely it will be to develop a leak.

- Most believe that modern coatings are generally more effective than older coatings, especially those installed before the 1940's. The older pipe is likely to experience a higher external corrosion incident rate as a result.

- External corrosion rates are generally higher at elevated temperatures. Since the pre-1940 pipe had a mean operating temperature of 125°F, higher than the mean operating temperature for pipe constructed during any other period, one would anticipate a higher external corrosion rate.

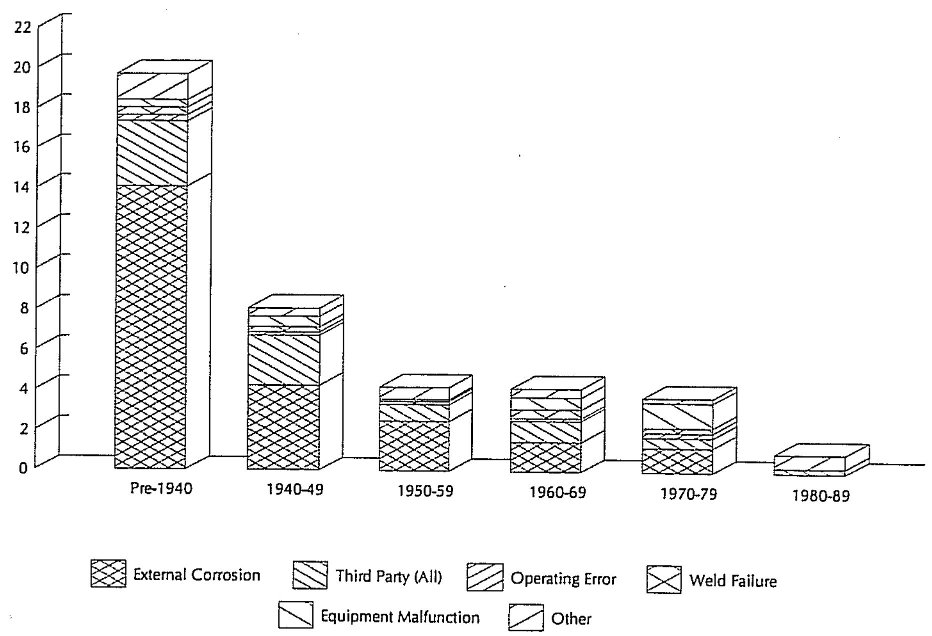
Table 4-8
Incident Rates By Decade of Construction

(Incidents Per 1,000 Mile Years)

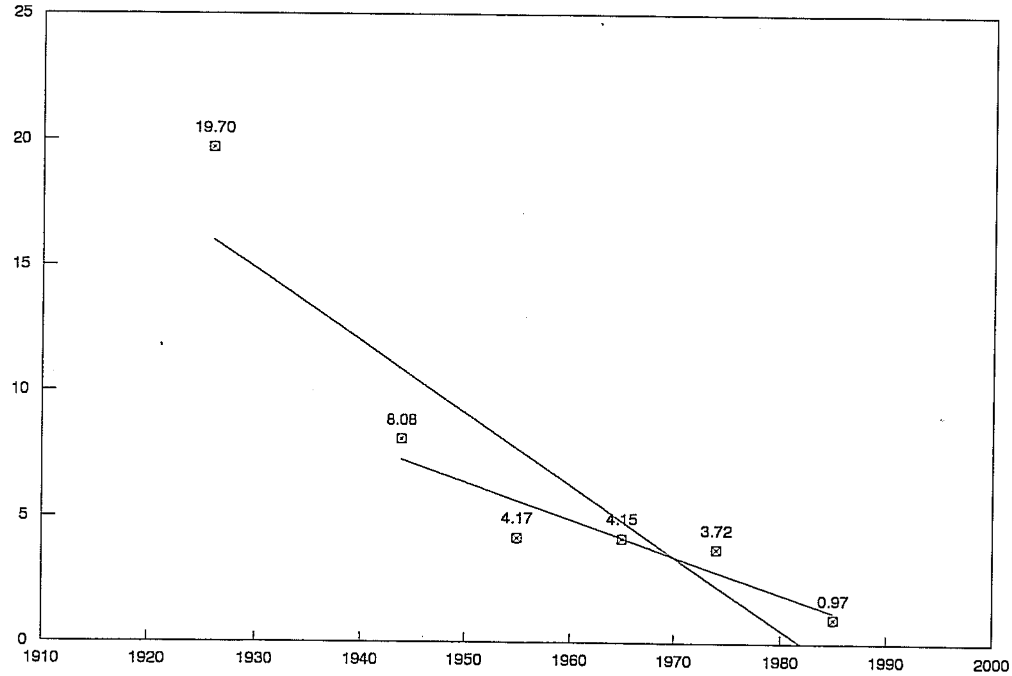
Cause of Incident	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal Corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3rd Party - Construction	1.96	1.06	0.68	0.66	0.25	0.28
3rd Party - Farm Equipment	0.53	1.33	0.05	0.00	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.70	8.08	4.17	4.15	3.72	0.97
Number of Mile Years	13,247	7,546	20,612	18,311	4,030	7,252
Average Year Pipe Constructed	1926	1944	1955	1965	1974	1985
Average Operating Temperature (°F)	125.2	79.7	89.4	91.4	99.8	104.1
Average Diameter (inches)	8.58	11.11	11.82	11.27	13.79	19.55
Average Spill Size (barrels)	162	492	246	1,306	53	789
Average Damage ($US 1983)	31,273	119,603	169,741	496,156	85,778	164,314

Incident Rates By Decade of Construction

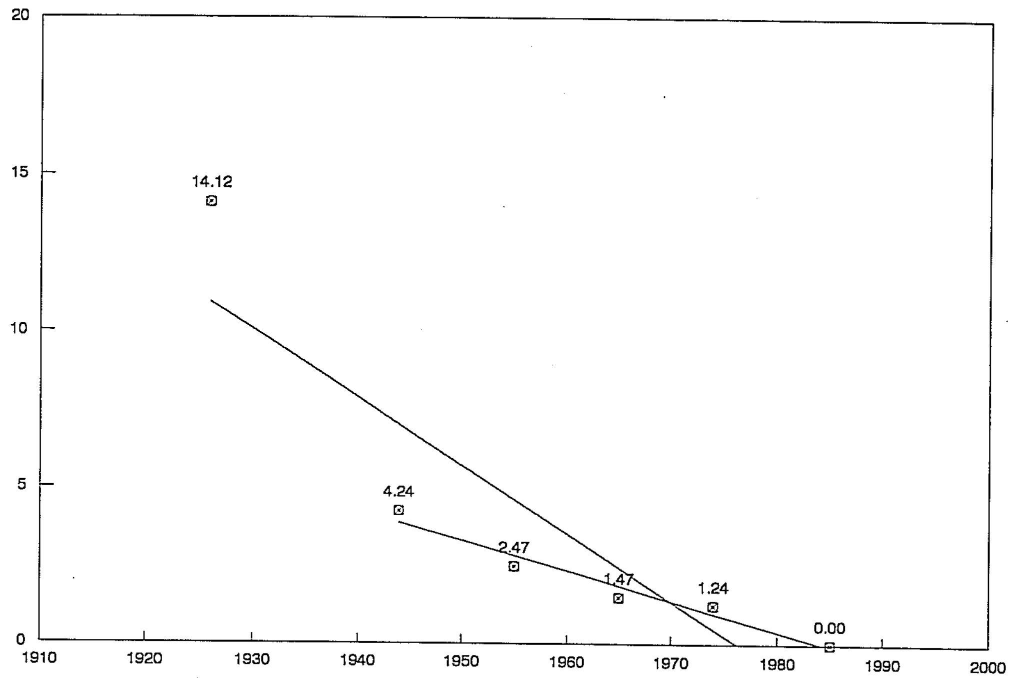
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Year of Pipe Construction
Incidents Per 1,000 Mile Years

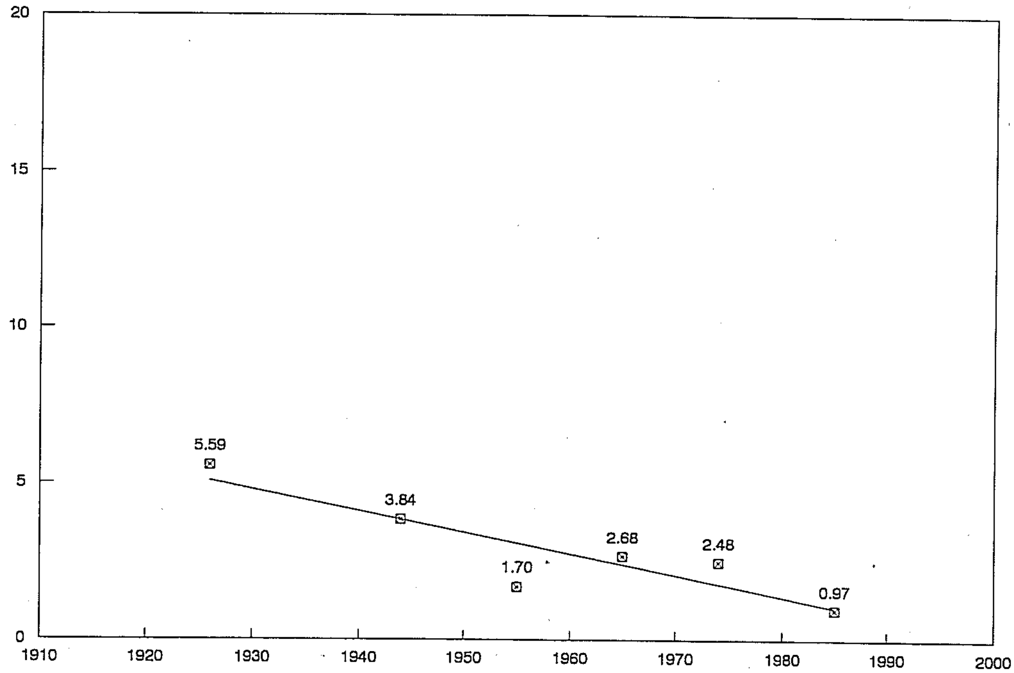


Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Year of Pipe Construction
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Year of Pipe Construction
Excludes All External Corrosion Incidents

Incidents Per 1,000 Mile Years



- Prior to the 1950's, it was common to install pipelines with little or no cathodic protection. For the most part, these older systems have either had new systems installed, or their older systems upgraded, to be consistent with present day practices. However, they often operated for several years with inadequate or no cathodic protection. The corrosion which occurred during these early years likely increased the resulting external corrosion leak incident rate.

An ordinary least squares line of best fit was determined for the external corrosion data only. Using all data, it indicated that the external corrosion rate declined by 0.217 incidents per year per 1,000 mile years, with an *R squared* of 0.79. A similar regression was performed excluding all pipe constructed prior to 1940. This regression indicated an external corrosion rate reduction of 0.097 incidents per year per 1,000 mile years, with an *R squared* of 0.95. However, it should be noted that both of these regressions resulted in a least squares line fit which would indicate a negative incident rate during the study period, which is impossible. However, the point should be made that there is a strong statistical relationship between pipe age and rate of external corrosion; the newer the pipe, the lower the external corrosion incident rate.

A third ordinary least squares line of best fit was prepared for leaks caused by all causes except external corrosion. It indicated that the incident rate for these leaks decreased at the rate of 0.069 incidents per year per 1,000 mile years. The resulting *R squared* was 0.80.

It is interesting to note that the leak incident rate for pipe constructed during the 1950's, 60's and 70's was relatively constant, at about 4 incidents per 1,000 mile years. However, for pipe installed during the 1980's, the incident rate dropped to roughly 1 incident per 1,000 mile years. At the present, we believe that it is too soon to conclude whether or not this was simply a result of the limited time in service, or the result of any changes in pipeline construction or other practices. It will be interesting to note during future studies whether or not this difference continues.

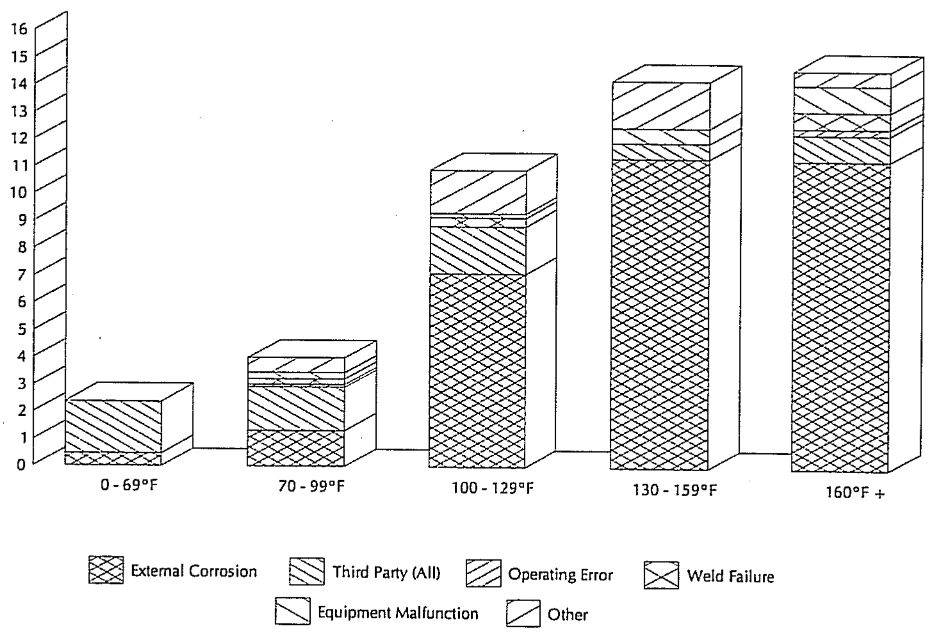
4.9 Operating Temperature Effects

As referenced in several earlier subsections, the study data indicated that operating temperature had a significant effect on leak incident rates. Generally, the higher the operating temperature, the higher the resulting incident rate. This data is presented in Table 4-9.

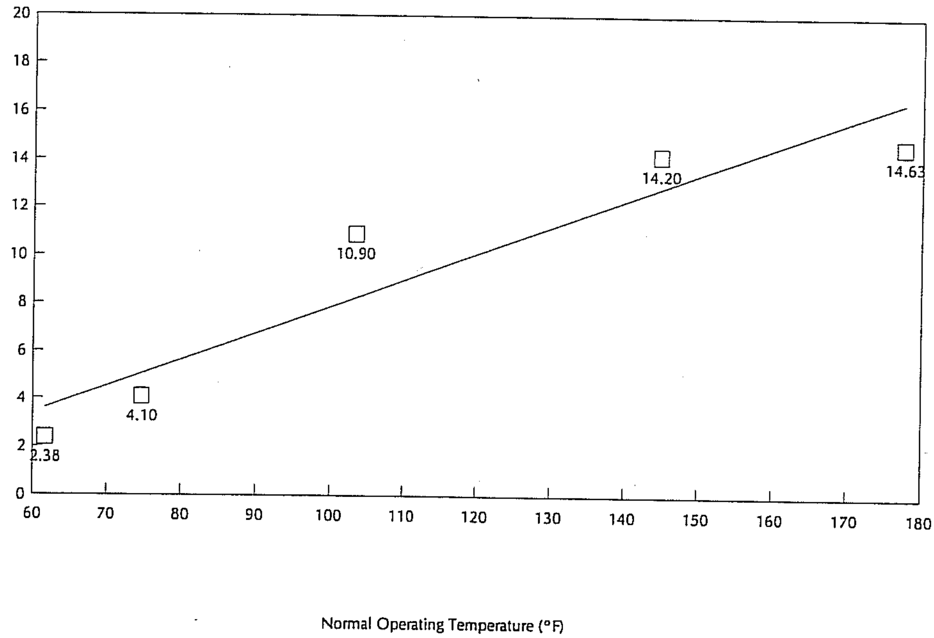
Table 4-9
Incident Rates By Normal Operating Temperature
(Incidents Per 1,000 Mile Years)

Cause of Incident	0 - 69°F	70 - 99°F	100 - 129°F	130 - 159°F	160°F +
External Corrosion	0.48	1.33	7.11	11.36	11.31
Internal Corrosion	0.00	0.21	0.32	0.57	0.08
3rd Party - Construction	1.91	0.94	0.95	0.57	0.60
3rd Party - Farm Equipment	0.00	0.30	0.47	0.00	0.08
3rd Party - Train Derailment	0.00	0.04	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.06	0.16	0.00	0.15
3rd Party - Other	0.00	0.24	0.16	0.00	0.15
Human Operating Error	0.00	0.11	0.00	0.00	0.23
Design Flaw	0.00	0.04	0.00	0.00	0.00
Equipment Malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld Failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	1.11	1.14	0.45
Total	2.38	4.01	10.90	14.20	14.63
Number of Mile Years	2,097	46,641	6,332	1,760	13,260
Mean Year Pipe Constructed	1960	1959	1953	1947	1951
Mean Operating Temperature (°F)	61.66	74.72	103.37	144.84	177.63
Mean Diameter (inches)	8.62	12.58	11.88	9.92	12.96
Average Spill Size (barrels)	12	480	72	7	601
Average Damage ($US 1983)	48,407	244,643	36,214	10,465	95,863

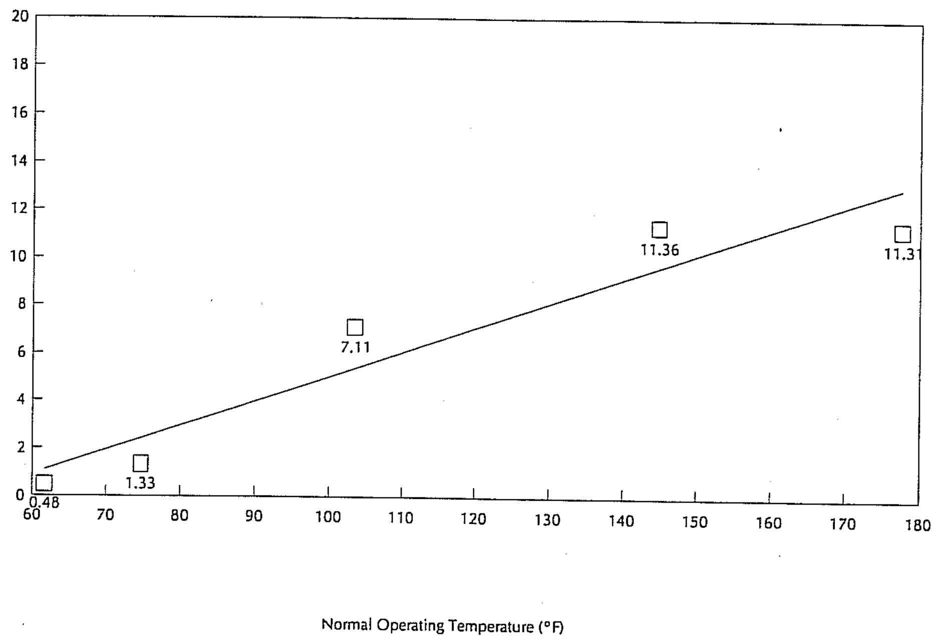
Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years

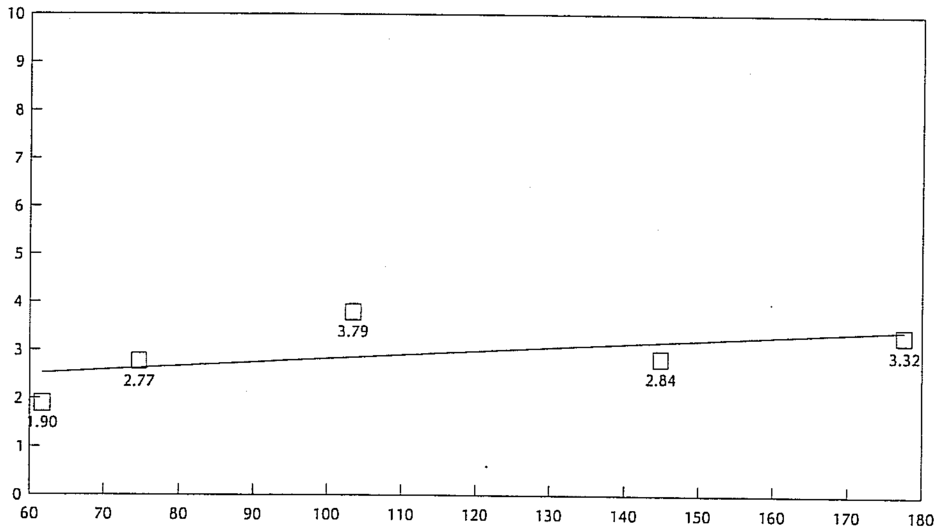


Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Normal Operating Temperature
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Incident Rates for Other Causes By Normal Operating Temperature
(Excludes All External Corrosion Incidents)

Incidents Per 1,000 Mile Years



Normal Operating Temperature (°F)

With the exception of the relatively new pipelines operating at above 180°F (most were built around 1979), higher operating temperatures were directly related to higher leak incident rates. However, the data also indicated that the pipelines operated between 130 and 159°F were also the oldest. As a result, a logistic regression was performed to determine whether or not pipe age was masking the pipe operating temperature effects. The logistic regression results indicated that while holding various factors constant, including pipe age, operating temperature was positively related to the probability of a leak occurring from external corrosion. Operating temperature was not statistically related, however, to the probability of leaks occurring from other causes.

Ordinary least squares lines of best fit were also calculated to evaluate the statistical relevance of this data. For all leaks, the line indicated an increase of 0.11 incidents per °F per 1,000 mile years, with an *R squared* of 0.89. For external corrosion leaks only, the regression resulted in an increase of 0.10 incidents per °F per 1,000 mile years, with an *R squared* of 0.91. For all leaks, excluding external corrosion leaks, the regression resulted in an increase of 0.0077 incidents per °F per 1,000 mile years, with an *R squared* of only 0.28, which reaffirms the logistical regression results that the probability of leaks occurring from other causes was not affected by operating temperature.

The data also indicated that spill sizes and monetary damage did not appear to be affected by operating temperature.

4.10 Pipe Diameter Effects

The variance in leak incident rates between pipe diameter ranges has been discussed somewhat in preceding subsections. A good deal of variance exists, as evidenced by the data presented in Table 4-10.

To begin with, the leak incident rate for pipe 7" in diameter and less was over three times that for pipe larger than 20" in diameter, 10.35 versus 3.17 incidents per 1,000 mile years. This is especially noteworthy since the mean operating temperature for the small diameter pipe was only 77.9°F, the lowest of any diameter range. However, the age of pipe in this category and in the 8-10 inch category was fairly old, which would tend to result in higher incident rates, as we have already seen.

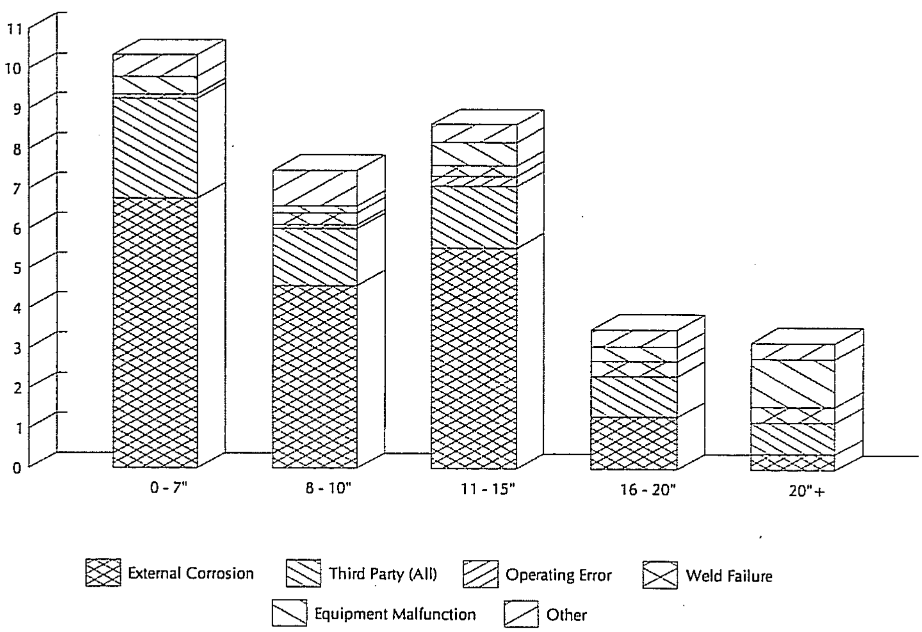
The category of pipe in the 11-15 inch diameter range also had a relatively high incident rate (8.62 incidents per 1,000 mile years). Although these lines were a good deal newer, they operated at a higher mean operating temperature.

Surprisingly, the 16-20 inch pipe diameter range had a relatively low leak rate (3.49 incidents per 1,000 mile years), despite having the highest mean operating temperature range.

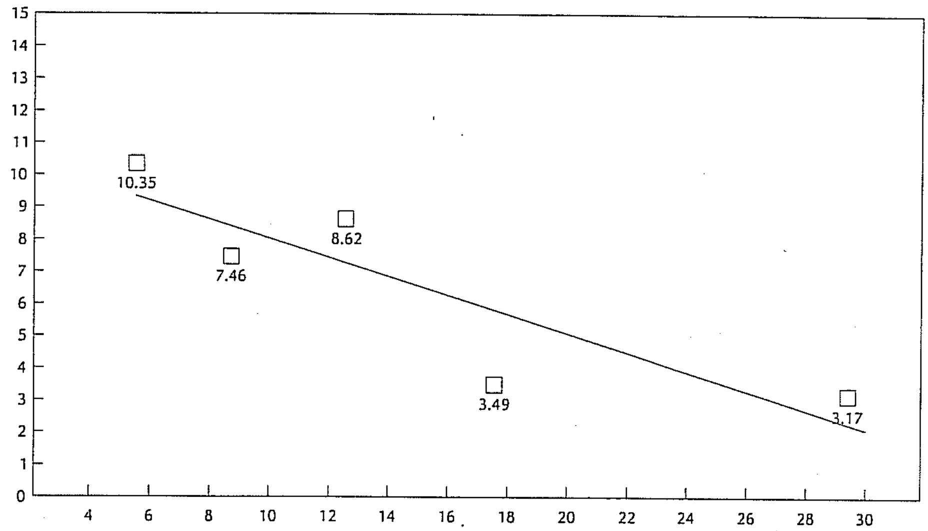
Table 4-10
Incident Rates By Pipe Diameter
(Incidents Per 1,000 Mile Years)

Cause of Incident	0 - 7"	8 - 10"	11 - 15"	16 - 20"	20" +
External Corrosion	6.75	4.56	5.51	1.31	0.40
Internal Corrosion	0.33	0.27	0.13	0.07	0.00
3rd Party - Construction	1.96	0.83	0.97	0.36	0.79
3rd Party - Farm Equipment	0.33	0.27	0.00	0.51	0.00
3rd Party - Train Derailment	0.00	0.00	0.06	0.07	0.00
3rd Party - External Corrosion	0.22	0.13	0.06	0.00	0.00
3rd Party - Other	0.00	0.20	0.45	0.07	0.00
Human Operating Error	0.11	0.10	0.26	0.00	0.00
Design Flaw	0.00	0.03	0.00	0.00	0.40
Equipment Malfunction	0.44	0.17	0.58	0.36	1.19
Maintenance	0.00	0.03	0.06	0.15	0.00
Weld Failure	0.00	0.30	0.26	0.36	0.40
Other	0.22	0.57	0.26	0.22	0.00
Total	10.35	7.46	8.62	3.49	3.17
Number of Mile Years	9,183	30,021	15,435	13,760	2,525
Mean Year Pipe Constructed	1951	1948	1962	1964	1984
Mean Operating Temperature (°F)	77.90	94.11	104.81	108.44	91.17
Mean Diameter (inches)	5.6	8.7	12.6	17.6	29.4
Average Spill Size (barrels)	55	190	489	1,980	88
Average Damage ($US 1983)	18,139	63,018	432,382	130,807	354,158

Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years

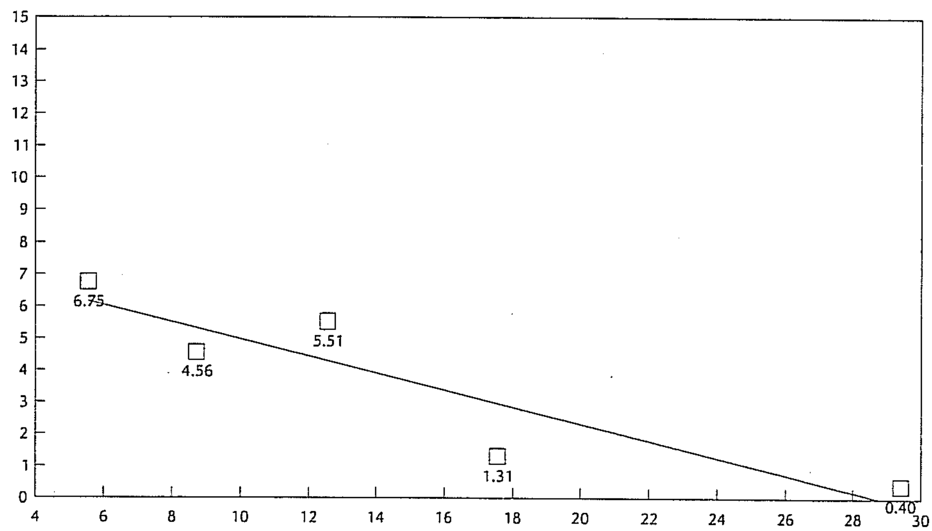


Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years



Pipe Diameter (inches)

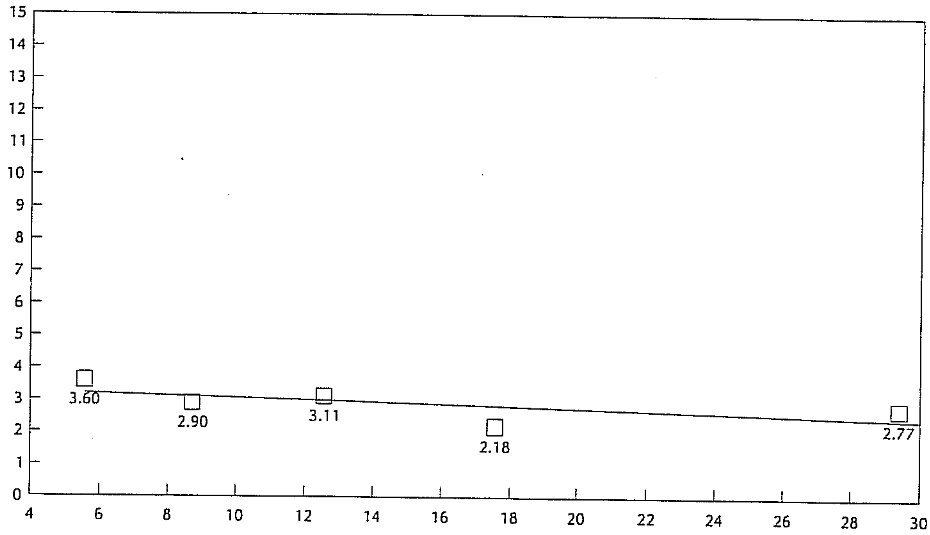
Ordinary Least Squares Line of Best Fit
External Corrosion Incident Rates By Pipe Diameter
Incidents Per 1,000 Mile Years



Pipe Diameter (inches)

Ordinary Least Squares Line of Best Fit
Incident Rates For Other Causes By Pipe Diameter
Excludes All External Corrosion Incidents

Incidents Per 1,000 Mile Years



Pipe Diameter (inches)

The largest pipe, over 20 inches in diameter, had the lowest leak incident rate, 3.17 incidents per 1,000 mile years. However, this pipe was the newest of any category, with a mean year of pipe construction of 1984. The mean operating temperature was moderate.

Three ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.29 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.76. The second, included only external corrosion leaks; it indicated a reduction of 0.26 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.82. The third was performed using all leaks except external corrosion caused leaks; it resulted in a reduction of only 0.03 incidents per diameter inch per 1,000 mile years, with an *R squared* of 0.31. In short, there was a correlation between pipe diameter and the incident rate for external corrosion leaks, but not for leaks caused by other factors. There are several possible explanations for this correlation:

- Larger diameter pipelines represent a larger capital investment for the pipeline operator. As a result, there may be a greater proportion of the operators' resources directed toward their construction, operation, and maintenance.

- The larger diameter lines are often more important to the operators' overall operation and/or revenue generation. As a result, they may receive more attention.

- The larger lines are likely to create a greater perceived risk in the event of their rupture. This could also cause an operator to direct more resources to their protection.

4.11 Leak Detection Systems

The data was sorted into pipelines with some sort of supervisory control and data acquisition (SCADA) systems and those without. 85% of the regulated hazardous liquid pipelines hae SCADA systems. The leak incident rate for pipelines without these types of systems was almost twice the incident rate for systems with SCADA, 11.00 versus 6.29 incidents per 1,000 mile years. However, *this does not indicate that SCADA systems reduce leak incident rates.*

It should be noted that in general, the pipe with SCADA was seven years newer, had an operating temperature about 7°F higher, and had a mean diameter 3" greater than the systems without SCADA. We have already seen that these factors did affect incident rates. However, adding meters and telecommunications equipment to provide a SCADA system does not.

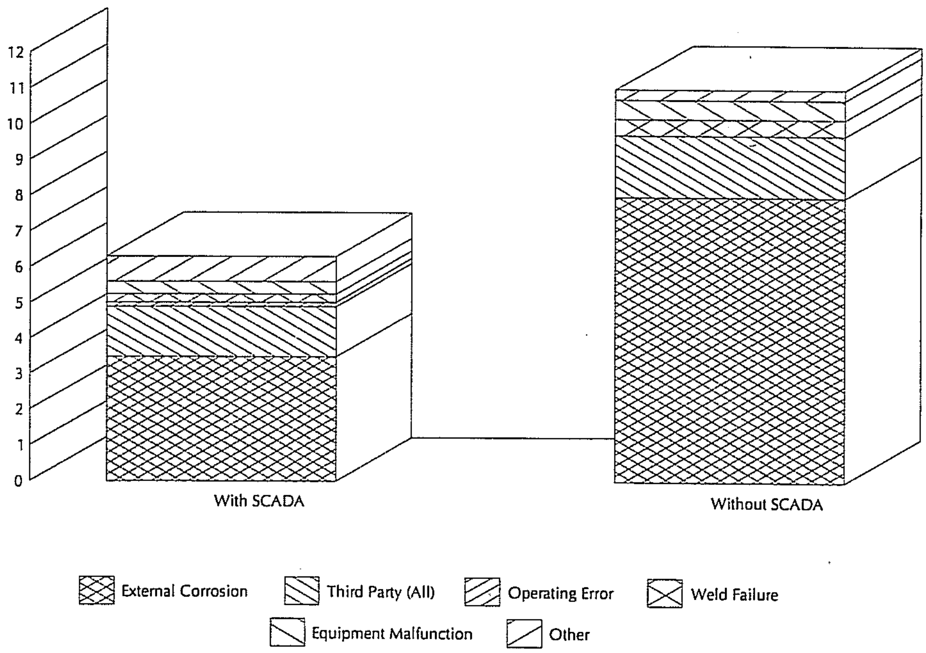
Table 4-11
Incidents By Leak Detection System
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	With SCADA		Without SCADA	
	Number	Rate	Number	Rate
External Corrosion	214	3.49	87	7.98
Internal Corrosion	13	0.21	1	0.09
3rd Party - Construction	53	0.86	11	1.01
3rd Party Farm Equipment	15	0.24	3	0.28
3rd Party - Train Derailment	2	0.03	0	0.00
3rd Party - External Corrosion	5	0.08	2	0.18
3rd Party - Other	11	0.18	3	0.28
Human Operating Error	8	0.13	0	0.00
Design Flaw	2	0.03	0	0.00
Equipment Malfunction	21	0.34	6	0.55
Maintenance	5	0.08	0	0.00
Weld Failure	14	0.23	5	0.46
Other	23	0.37	2	0.18
Total	386	6.29	120	11.00
Number of Mile Years	61,351		10,904	
Mean Year Pipe Constructed	1952		1945	
Mean Operating Temperature (°F)	114.3		107.0	
Mean Diameter (inches)	12.4		9.5	
Average Spill Size (barrels)	476.7		157.6	
Average Damage ($US 1983)	153,937		55,215	

Incident Rate Comparison

Incidents Per 1,000 Mile Years



It's interesting to note that the average spill size was nearly 3 times greater for pipelines with SCADA systems than those without. This was surprising, since it is generally accepted that SCADA systems provide a means of detecting leaks quickly, minimizing spill volumes. However, pipe diameter, fluid viscosity, line hydraulics and other factors also affect spill volumes. Assuming a mean 0.25" wall thickness and all other factors being equal, one would have expected a 75% greater spill volume from the relatively large diameter pipe with SCADA systems.

4.12 Cathodic Protection System

As indicated in Table 4-1, nearly 60% of the leaks on California's regulated pipeline systems were caused by external corrosion. As a result, we attempted to evaluate the effectiveness of cathodic protection systems and cathodic protection surveys. This section reviews applicable regulations and the data collected during the study.

Generally, 49 CFR 195.414 requires that all interstate pipelines which have an effective external coating must be cathodically protected, except for break out tank areas and buried pump station piping. The California Pipeline Safety Act requires that all intrastate pipelines be brought into compliance with these federal regulations according to a graduated five year schedule; all intrastate lines, including those which operate at less than 20% SMYS, were scheduled to comply by January 1, 1991. In other words, all regulated externally coated pipelines were required to have cathodic protection systems installed by the end of the study period.

49 CFR 195.416 requires that the cathodic protection systems on all cathodically protected interstate pipelines be inspected at least once each calendar year, at intervals not exceeding 15 months. In addition, each interstate pipeline operator is required to inspect their cathodic protection system rectifiers at intervals not exceeding two and one-half months, but at least six times a year. The California Pipeline Safety Act incorporates these requirements by reference for intrastate pipelines.

Nearly 100% of the regulated hazardous liquid pipelines were protected by either impressed current or sacrificial anode cathodic protection systems. We did not find a statistically relevant difference in the effect on leak incident rates between the two types of systems. However, we found a significant difference between protected and unprotected pipelines. As depicted in Table 4-12, unprotected pipelines had an external corrosion leak incident rate over five times higher than protected lines.

This is especially noteworthy since the unprotected lines, although a small sample, were much newer. They also operated at a higher mean operating temperature and were smaller in diameter.

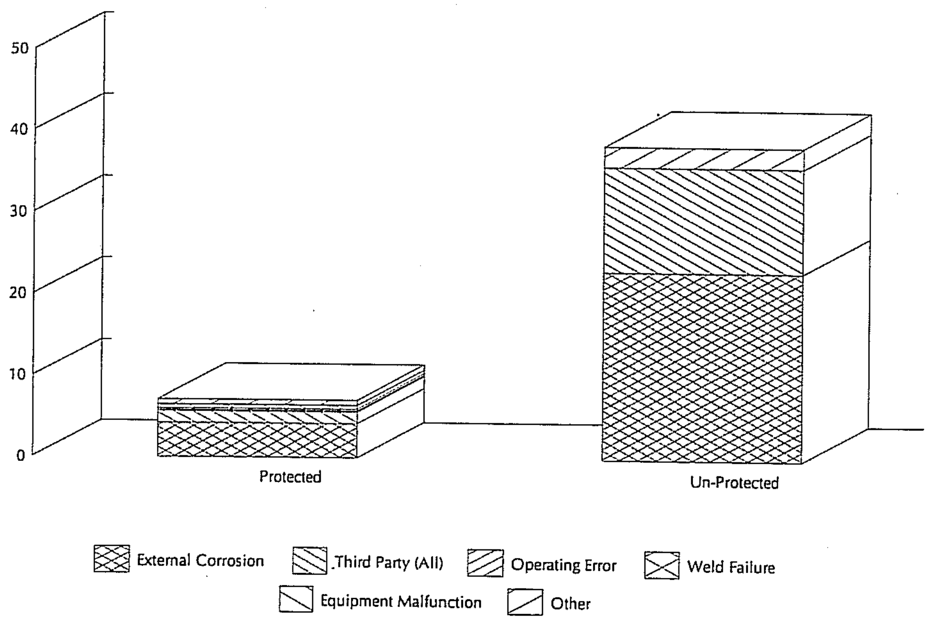
Table 4-12
Cathodic Protection System
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	Protected Lines		Un-Protected Lines	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	295	4.23	9	23.12
Internal Corrosion	14	0.20	0	0.00
3rd Party - Construction	64	0.92	1	2.57
3rd Party Farm Equipment	18	0.26	0	0.00
3rd Party - Train Derailment	2	0.03	0	0.00
3rd Party - External Corrosion	5	0.07	1	2.57
3rd Party - Other	11	0.16	3	7.71
Human Operating Error	8	0.11	0	0.00
Design Flaw	2	0.03	0	0.00
Equipment Malfunction	27	0.39	0	0.00
Maintenance	5	0.07	0	0.00
Weld Failure	19	0.27	0	0.00
Other	25	0.36	1	2.57
Total	495	7.10	15	38.53
Number of Mile Years	69,756		389	
Mean Year Pipe Constructed	1957		1970	
Mean Operating Temperature (°F)	97		138	
Mean Diameter (inches)	12.4		8.8	
Average Spill Size (barrels)	418		39	
Average Damage ($US 1983)	145,091		82,760	

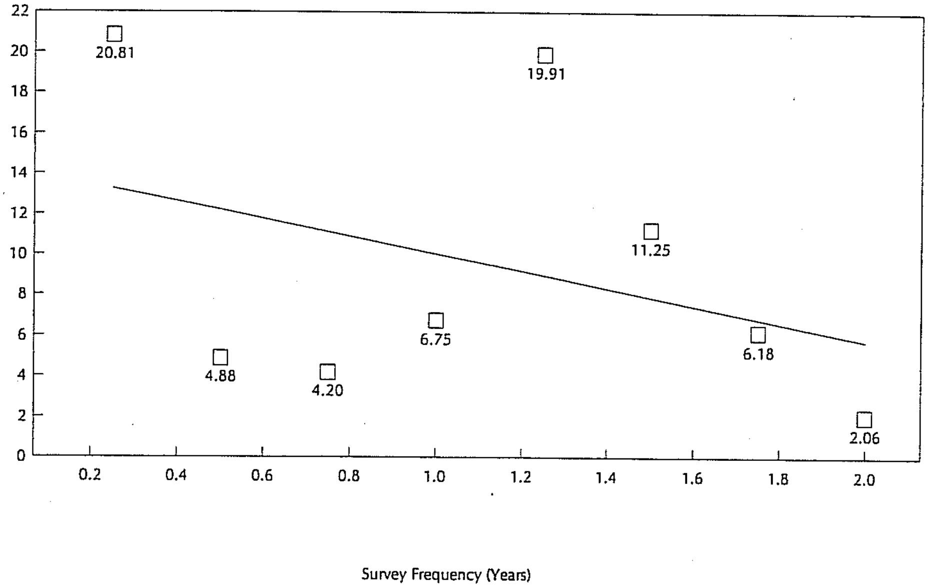
Incident Rate Comparison

Incidents Per 1,000 Mile Years



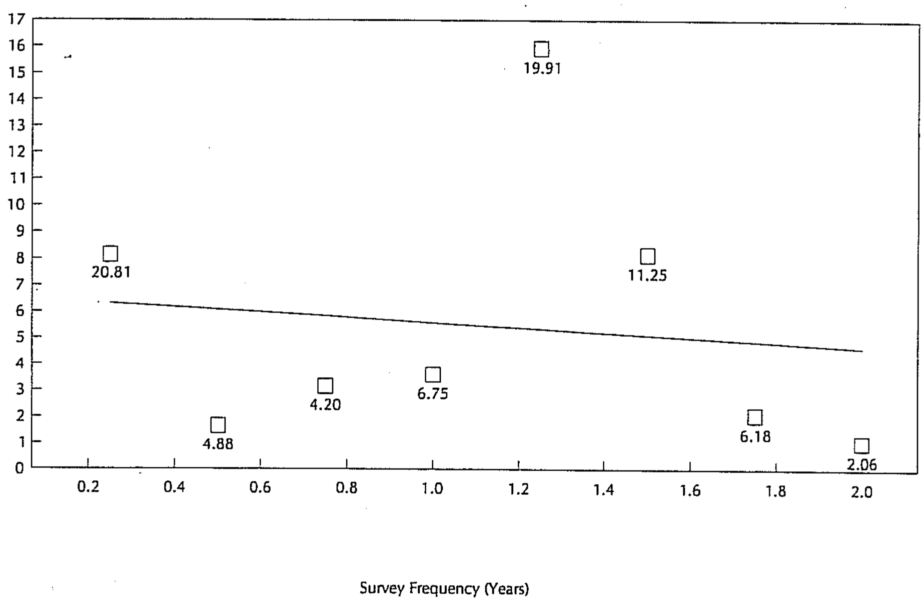
Ordinary Least Squares Line of Best Fit
Cathodic Protection System Survey Frequency
Incident Rate Comparison - All Leak Incidents

(Incidents Per 1,000 Mile Years)



Ordinary Least Squares Line of Best Fit
Cathodic Protection System Survey Frequency
Incident Rate Comparison - External Corrosion Leak Incidents Only

(Incidents Per 1,000 Mile Years)



It is doubtful that whether or not a pipeline system was protected had any relation to spill volume or extent of damage; although this data has been presented for completeness. It does appear, however, that protection systems reduced the frequency of pipeline ruptures due to external corrosion.

Data was also collected regarding the frequency of cathodic protection surveys. Table 4-12 shows the overall and external corrosion only incident rates by the average frequency of cathodic protection surveys. Ordinary least squares lines of best fit were prepared to determine whether or not the frequency of cathodic protection surveys had any statistical relevance to leak incident rates. Surprisingly, the ordinary least squares lines of best fit showed a slightly decreasing incident rate with less frequent surveys. However, there was little if any statistical relevance to this data; the *R squared* values for all incidents and external corrosion only incidents were only 0.13 and 0.01 respectively.

A multinomial logistic regression analysis was performed to analyze this parameter. It indicated that the frequency of cathodic protection surveys was not statistically correlated with the external corrosion leak incident rate.

However, the data indicated that the probability of a leak occurring because of other causes was related to the frequency of cathodic protection surveys; that is, as the frequency of cathodic protection surveys decreased, the chance of an incident resulting from causes except external corrosion decreased as well. This effect was significant at the 1.9% probability level using the asymptotic t-distribution, holding variables such as length, year of construction and operating temperature constant. We believe that this result is circumstantial and does not indicate that cathodic protection surveys themselves decrease pipeline safety.

Table 4-12A presents the average cathodic protection survey interval compiled in a different format. The average cathodic protection survey interval was determined by dividing the total number of surveys conducted during the study period by 10 years, for each pipeline included in the study. The data was then combined into four categories: pipelines with average survey intervals up to one year; from over one year up to two years; from over two years to five years; and those from over five years up to ten years.

As indicated, the highest overall and external corrosion rate occurred in the group with cathodic protection surveys conducted between one and two years. This group had the highest mean operating temperature of any group, with a mean year of pipe construction near the average for all pipelines included in the study.

The group with the least frequent surveys (5.1 to 10.0 years) had the lowest overall and external corrosion rates. This is somewhat surprising since this was also the oldest pipe group. However, it had by far the lowest mean operating temperature.

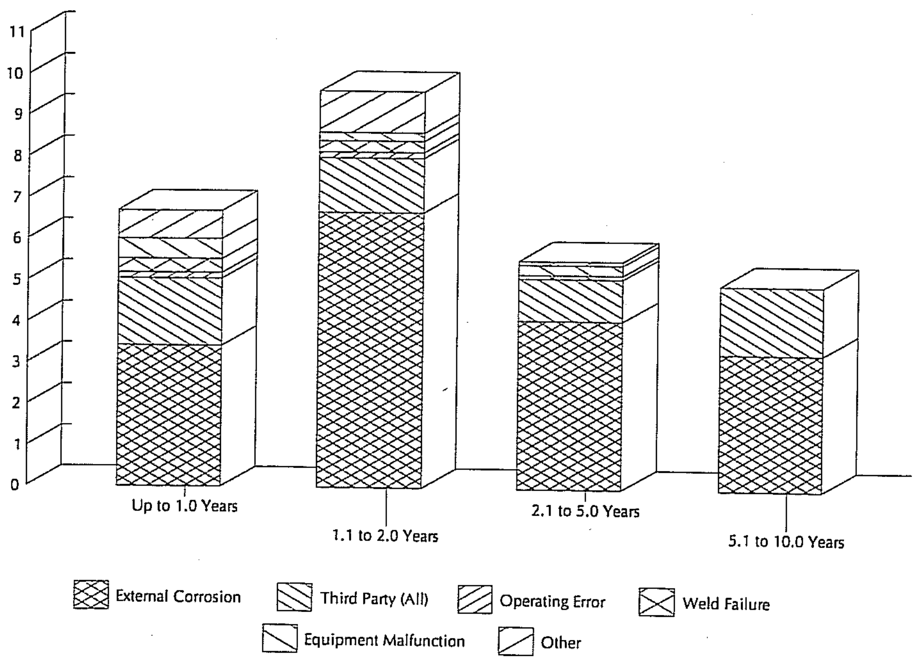
Table 4-12A
Average Cathodic Protection Survey Interval During Study Period
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 1.0 Years		1.1 to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	146	3.43	100	6.68	48	4.10	4	3.33
Internal Corrosion	10	0.24	4	0.27	0	0.00	0	0.00
3rd Party - Construction	46	1.08	9	0.60	6	0.51	1	0.83
3rd Party Farm Equipment	10	0.24	7	0.47	1	0.09	0	0.00
3rd Party - Train Derailment	1	0.02	0	0.00	1	0.09	0	0.00
3rd Party - External Corrosion	3	0.07	0	0.00	3	0.26	1	0.83
3rd Party - Other	9	0.21	4	0.27	1	0.09	0	0.00
Human Operating Error	6	0.14	2	0.13	0	0.00	0	0.00
Design Flaw	1	0.02	1	0.07	0	0.00	0	0.00
Equipment Malfunction	21	0.49	3	0.20	3	0.26	0	0.00
Maintenance	5	0.12	0	0.00	0	0.00	0	0.00
Weld Failure	14	0.33	4	0.27	1	0.09	0	0.00
Other	13	0.31	10	0.67	1	0.09	0	0.00
Total	285	6.70	144	9.62	65	5.55	6	4.99
Number of Mile Years	42,524		14,961		11,713		1,202	
Mean Year Pipe Constructed	1954		1958		1962.8		1953	
Mean Operating Temperature (°F)	93.3		98.5		98.1		73.8	
Mean Diameter (Inches)	11.1		16.1		11.5		8.8	

Incident Rate Comparison

Incidents Per 1,000 Mile Years



4.13 Pipe Specification Effects

Another characteristic which could influence the propensity of leak incidents is the type of steel used in construction. Table 4-13 demonstrates that pipes constructed to different specifications had different incident rates. However, it must be recognized that other factors also affected these rates.

We were surprised to find that 78% of California's regulated hazardous liquid pipe was constructed of ASTM X grade material. Normally, this pipe is manufactured from relatively high quality steel, with more strictly controlled chemistry. The mean year of construction and mean operating temperature for X-grade pipe were 1960 and 97.6°F respectively.

22% of the pipe was constructed of ASTM A53 material. The incident rate for this material was nearly 2.7 times higher than that for X-grade material. However, this pipe was on average 10 years older, which would tend to increase the incident rate. However, the mean operating temperature was about 12°F lower, which would tend to reduce it.

An extremely small sample of pipe fell into the *other* category (less than 1%). However, the leak incident rate for this sample was very high, nearly 14 times that of X-grade pipe. Although the pipe had a mean age nearly 10 years older, it operated at a mean operating temperature roughly 30°F cooler.

4.14 Pipe Type Effects

Table 4-14 presents the study data by the type of pipe installed. The data sample was broken down into five categories: submerged arc welded (SAW), seamless (SMLS), electric resistance welded (ERW), lap welded (LW) and other. It was distributed as follows:

Pipe Type	Percentage of Sample
Electric Resistance Welded	76.3%
Seamless	16.8%
Lap Welded	4.0%
Other	2.0%
Submerged Arc Welded	0.9%

Table 4-13
Incidents By Pipe Specification
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	X-Grade		A53 and Grade B		Other	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	87	1.80	103	7.64	8	41.72
Internal Corrosion	6	0.12	5	0.37	0	0.00
3rd Party - Construction	34	0.70	13	0.96	2	10.43
3rd Party Farm Equipment	10	0.21	5	0.37	0	0.00
3rd Party - Train Derailment	2	0.04	0	0.00	0	0.00
3rd Party - External Corrosion	2	0.04	3	0.22	0	0.00
3rd Party - Other	11	0.23	1	0.07	0	0.00
Human Operating Error	3	0.06	2	0.15	0	0.00
Design Flaw	0	0.00	1	0.07	0	0.00
Equipment Malfunction	16	0.33	9	0.67	0	0.00
Maintenance	2	0.04	1	0.07	0	0.00
Weld Failure	14	0.29	4	0.30	0	0.00
Other	13	0.27	2	0.15	1	5.21
Total	200	4.13	149	11.05	11	57.36
Number of Mile Years	48,412		13,489		192	
Mean Year Pipe Constructed	1960		1950		1950	
Mean Operating Temperature (°F)	97.6		85.3		67.1	
Mean Diameter (inches)	13.1		8.8		8.9	
Average Spill Size (barrels)	757		63		24	
Average Damage ($US 1983)	282,182		109,230		32,998	

Incident Rate Comparison

Incidents Per 1,000 Mile Years

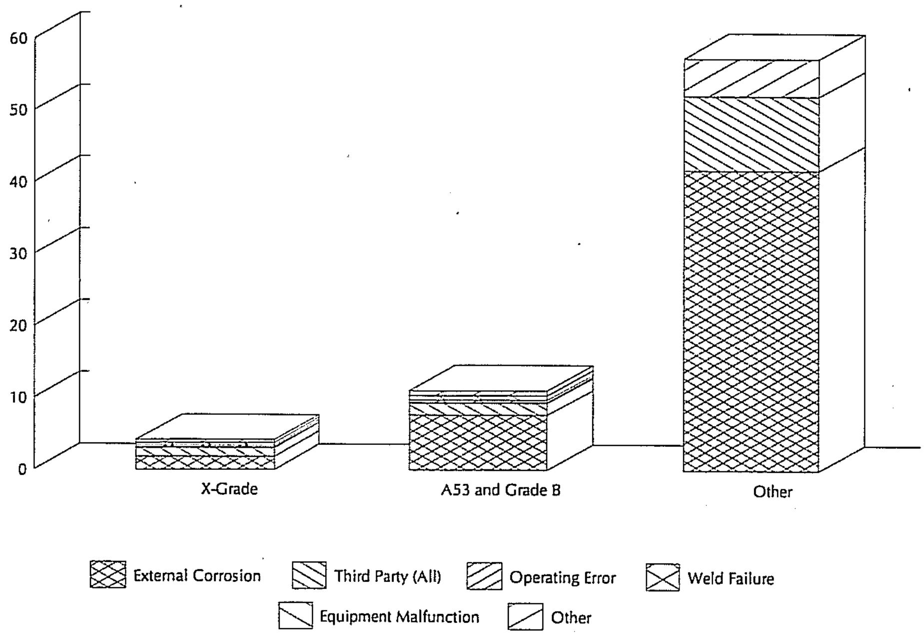
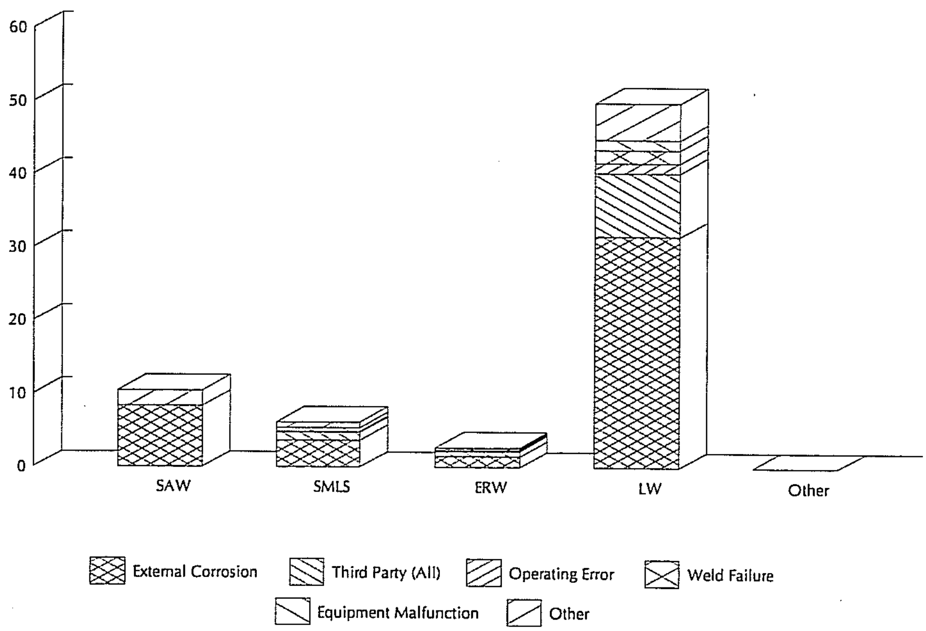


Table 4-14
Incident Rates By Pipe Type
(Incidents Per 1,000 Mile Years)

Cause of Incident	SAW	SMLS	ERW	LW	Other
External Corrosion	8.35	3.66	1.47	31.59	0.00
Internal Corrosion	2.09	0.22	0.02	1.83	0.00
3rd Party - Construction	0.00	0.86	0.45	6.41	0.00
3rd Party - Farm Equipment	0.00	0.22	0.02	1.83	0.00
3rd Party - Train Derailment	0.00	0.00	0.02	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.09	0.00	0.00
3rd Party - Other	0.00	0.00	0.12	0.46	0.00
Human Operating Error	0.00	0.11	0.05	1.37	0.00
Design Flaw	0.00	0.00	0.00	0.46	0.00
Equipment Malfunction	0.00	0.54	0.17	1.37	0.00
Maintenance	0.00	0.11	0.00	0.46	0.00
Weld Failure	0.00	0.00	0.12	1.83	0.00
Other	0.00	0.43	0.14	2.29	0.00
Total	10.44	6.14	2.68	49.90	0.00
Number of Mile Years	479	9,280	42,112	2,184	1,106
Mean Year Pipe Constructed	1978	1951	1963	1933	1952
Mean Operating Temperature (°F)	120.28	83.59	98.02	86.87	85.58
Average Spill Size (barrels)	5	83	285	87	0
Average Damage ($US 1983)	18,830	195,426	405,013	68,656	0

Incident Rates By Pipe Type
Incidents Per 1,000 Mile Years



The data indicated that lap weld pipe had a very high leak incident rate; nearly 50 incidents per 1,000 mile years. However, it was also the oldest pipe, with a mean year of construction of 1933.

Electric resistance welded (ERW) pipe had a comparatively low incidence of leaks, 2.7 incidents per 1,000 mile years. These leaks occurred on somewhat newer pipeline systems, with a mean year of construction of 1963; they also operated at a mean operating temperature near the mean for the entire pipe sample.

Seamless pipe observed an incident rate of 6.1 incidents per 1,000 mile years. However, this pipe sample was relatively old, with a mean year of construction of 1951. But the mean operating temperature was comparatively cool, 83.6°F.

Submerged arc welded pipe had a high incidence of leaks, 10.4 incidents per 1,000 mile years. This small pipe sample was relatively new, with a mean year of construction of 1978. However, the mean operating temperature was the highest of the sample, 120.3°F.

4.15 Operating Pressure Effects

Our analyses demonstrated that the relationship between normal operating pressure and the probability of pipe rupture was not statistically significant. Table 4-15 shows that there was considerable variance in the incident rate by pressure range. These differences, however, disappeared once variables such as age of pipe and operating temperature were controlled in the logistic regressions.

A simple ordinary least squares line of best fit was also determined using the overall leak data for each pressure range. The data indicated a declining leak incident rate as operating pressure increased, with an *R squared* of 0.32. However, as indicated above, the logistical regressions, which take other factors into account, did not indicate a correlation between operating pressure and leak incident rates.

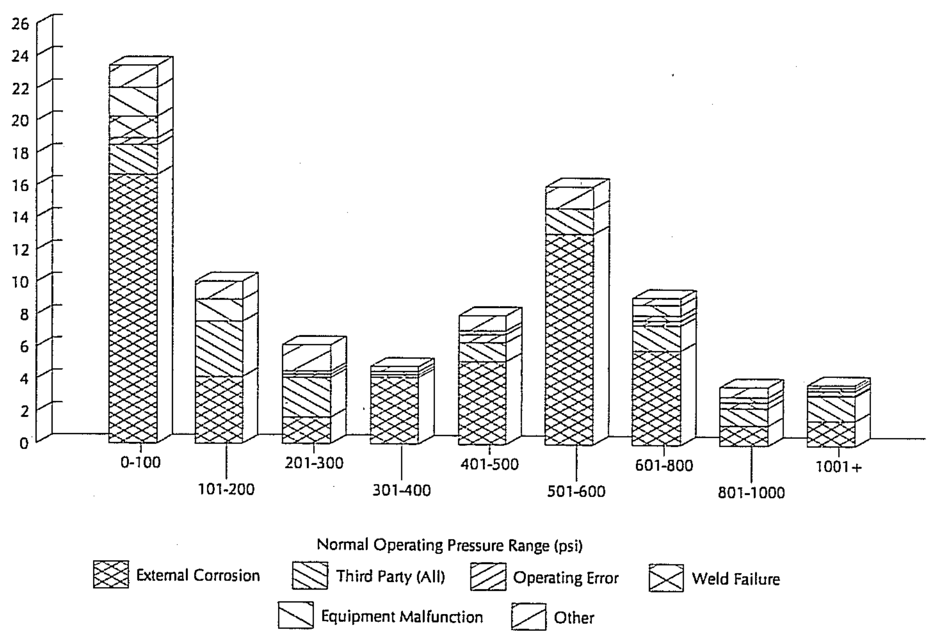
An ordinary least squares line of best fit was also prepared for spill size as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly 90 barrel increase in mean spill size per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.62. It should also be noted that mean pipe diameter was also slightly higher for pipelines operating within the higher operating pressure ranges; this would also skew the results in this direction.

A similar line of best fit was prepared for average damage as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly $37,000 ($US 1983) increase in average damager per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.58. However, as noted for spill volumes, pipe diameter variances would also generally affect spill damage.

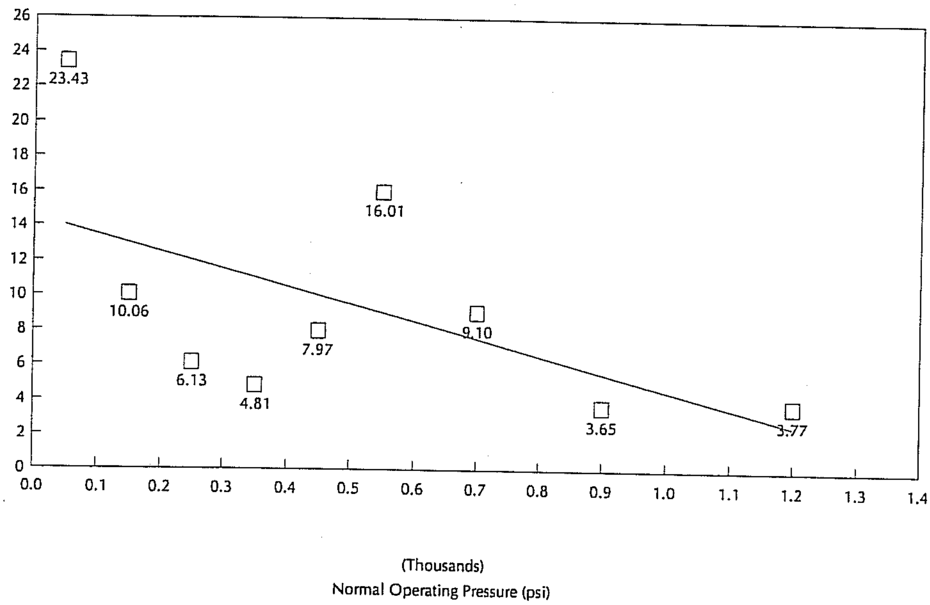
Table 4-15
Incident Rates By Normal Operating Pressure
(Incidents Per 1,000 Mile Years)

Cause of Incident	0-100 (psi)	101-200 (psi)	201-300 (psi)	301-400 (psi)	401-500 (psi)	501-600 (psi)	601-800 (psi)	801-1000 (psi)	1001+ (psi)
External Corrosion	16.67	4.11	1.63	4.12	5.16	13.05	5.83	1.26	1.58
Internal Corrosion	0.45	0.69	1.23	0.34	0.23	0.20	0.00	0.00	0.00
3rd Party - Construction	1.80	2.29	1.02	0.17	0.70	1.19	1.09	0.60	0.75
3rd Party - Farm Equipment	0.00	0.00	0.61	0.00	0.47	0.20	0.40	0.06	0.48
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14
3rd Party - External Corrosion	0.00	0.46	0.41	0.00	0.00	0.20	0.00	0.06	0.00
3rd Party - Other	0.00	0.69	0.41	0.00	0.00	0.00	0.10	0.36	0.14
Human Operating Error	0.45	0.00	0.20	0.00	0.47	0.00	0.30	0.00	0.07
Design Flaw	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.06	0.00
Equipment Malfunction	1.80	1.37	0.00	0.17	0.00	0.00	0.69	0.30	0.21
Maintenance	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.18	0.00
Weld Failure	1.35	0.00	0.20	0.00	0.23	0.00	0.30	0:36	0.27
Other	0.90	0.46	0.20	0.00	0.70	1.19	0.20	0.42	0.14
Total	23.43	10.06	6.13	4.81	7.97	16.01	9.10	3.65	3.77
Number of Mile Years	2,219	4,374	4,895	5,818	4,264	5,058	10,112	16,732	14,597
Average Year Pipe Constructed	1933	1954	1949	1940	1946	1934	1945	1958	1949
Average Operating Temperature (°F)	130.8	92.7	82.8	86.7	121.6	125.2	159.7	116.2	104.4
Average Diameter (inches)	9.9	11.0	8.6	12.7	8.7	9.3	11.1	16.4	11.7
Average Spill Size (barrels)	17	56	5	130	149	127	456	1,292	676
Average Damage ($US 1983, 1,000's)	59	71	38	50	26	13	70	167	586

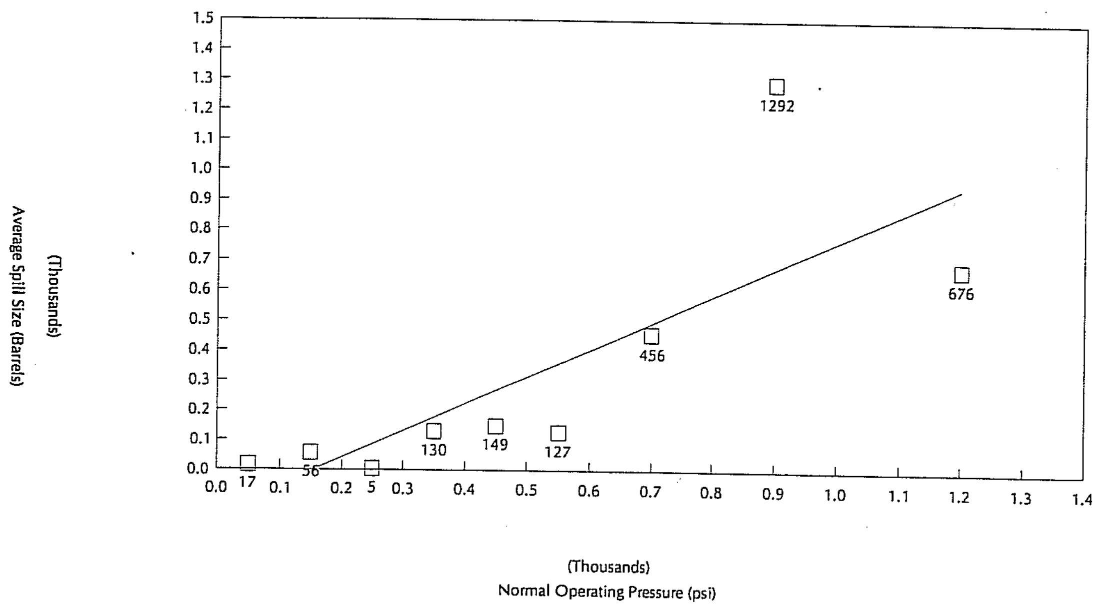
Incident Rates By Normal Operating Pressure
Incidents Per 1,000 Mile Years



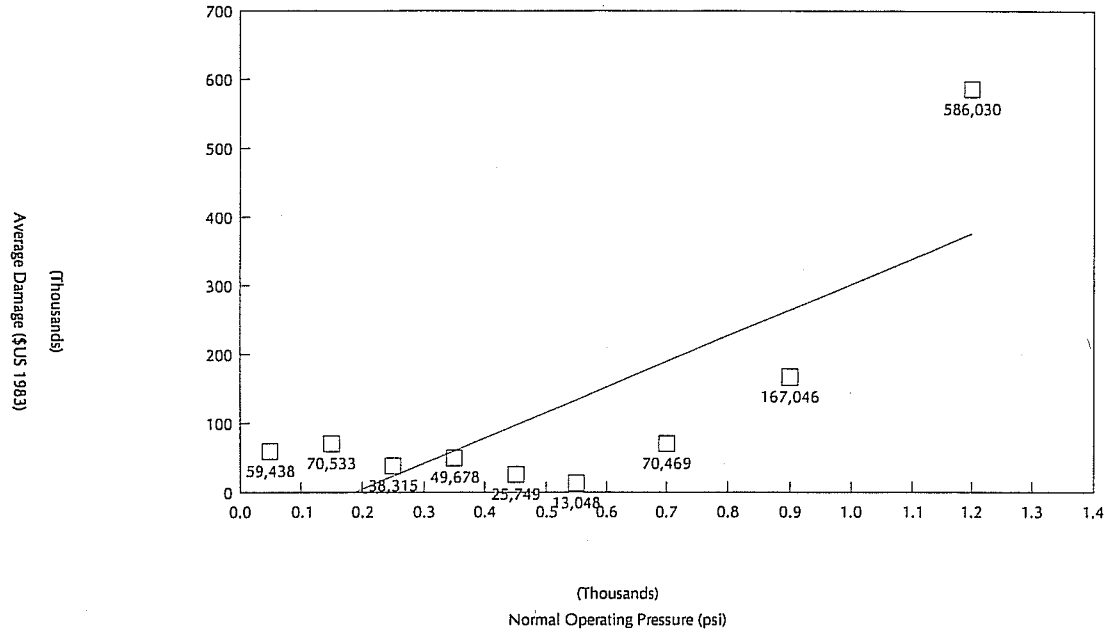
Ordinary Least Squares Line of Best Fit
Overall Incident Rates By Normal Operating Pressure
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
Average Spill Size By Normal Operating Pressure



Ordinary Least Squares Line of Best Fit
Average Damage By Normal Operating Pressure



4.16 External Pipe Coatings

This subsection examines the incident rates for various external pipe coatings. To accomplish this, the data sample was sorted into eight categories, which represented nearly all of the coatings installed on the pipelines included in this study. These coating types, their common and trade names, and the percentage of each in operation during the study period are presented below.

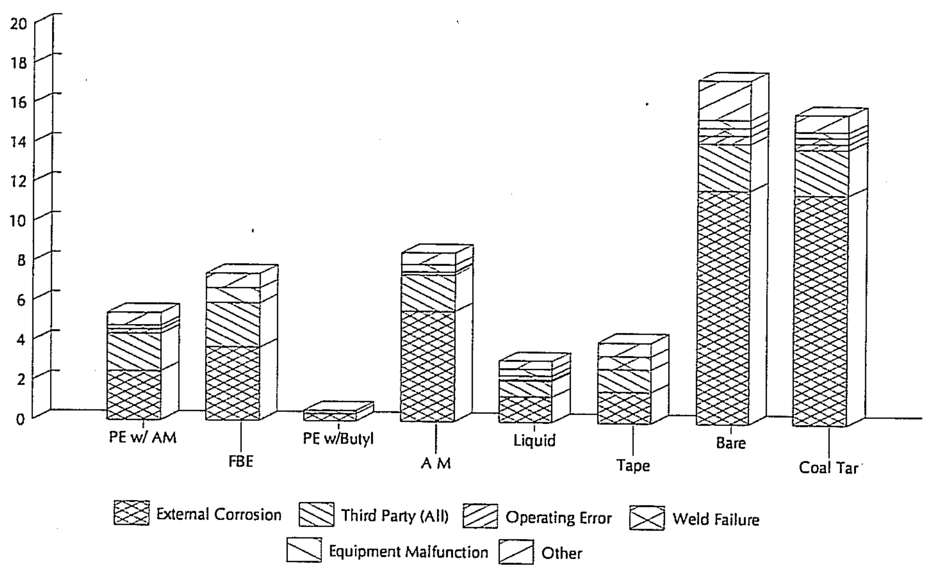
Coating Type	Percentage of Sample	Common/Trade Names
Extruded Polyethylene with Asphalt Mastic	6.5%	X-Tru-Coat Plexco EEC 60XT (X-Tru-Coat)
Fusion Bonded Epoxy	1.8%	FBE Mobilox Scotchcoat 206 or 202 Thin Film Epoxy
Extruded Polyethylene with Side Extruded Butyl	7.6%	Pritec
Extruded Asphalt Mastic	24.9%	Somastic Asphalt Mastic
Liquid Systems	41.6%	Coal Tar Epoxy Carboline Epoxy
Mill Applied Tape	6.0%	Polyken Tape YG III Plicoflex Raychem Hotclad Synergy
Coal Tar	4.7%	Coal Tar or Asphalt Enamel Wrapped
Bare Pipe	6.8%	N/A

Table 4-16 presents the incident rates by coating type. Although pipe age and operating temperatures had the greatest effect, there did appear to be differences in performance between the coating systems. As noted earlier in Table 4-1, the average external corrosion incident rate for all pipe included in this study was 4.18 incidents per 1,000 mile years. Generally, the more modern coatings had external corrosion incident rates lower than average, some significantly lower. The older, extruded asphalt mastic systems had external corrosion incident rates slightly higher than average. Somewhat surprisingly, the coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as the bare pipe.

Table 4-16
Incident Rates By Coating Type
(Incidents Per 1,000 Mile Years)

Cause of Incident	Extruded PE with Asphalt Mastic	Fusion Bonded Epoxy	Extruded PE with Side Extruded Butyl	Extruded Asphalt Mastic	Liquid Systems	Mill Applied Tape	Bare Pipe	Coal Tar or Asphalt Enamel Wrapped
External Corrosion	2.49	3.71	0.36	5.56	1.27	1.58	11.77	11.59
Internal Corrosion	0.21	0.00	0.00	0.27	0.20	0.00	0.20	0.29
3rd Party - Construction	1.04	0.00	0.18	1.31	0.49	0.45	1.60	1.45
3rd Party - Farm Equipment	0.42	2.22	0.00	0.22	0.00	0.45	0.00	0.87
3rd Party - Train Derailment	0.21	0.00	0.00	0.00	0.03	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.16	0.13	0.00	0.00	0.00
3rd Party - Other	0.21	0.00	0.00	0.16	0.16	0.23	0.80	0.00
Human Operating Error	0.21	0.00	0.00	0.11	0.07	0.00	0.40	0.29
Design Flaw	0.00	0.00	0.00	0.05	0.00	0.23	0.00	0.00
Equipment Malfunction	0.21	0.74	0.00	0.33	0.33	0.00	0.40	0.29
Maintenance	0.00	0.00	0.00	0.11	0.03	0.00	0.00	0.00
Weld Failure	0.00	0.00	0.00	0.05	0.20	0.68	0.40	0.29
Other	0.42	0.74	0.00	0.16	0.20	0.45	1.80	0.58
Total	5.40	7.41	0.53	8.51	3.09	4.06	17.35	15.65
Number of Mile Years	4,814	1,349	5,625	18,342	30,700	4,435	5,013	3,450
Mean Year Pipe Constructed	1974	1984	1973	1956	1959	1984	1948	1962
Mean Operating Temperature (°F)	107.4	115.6	105.8	80.5	98.1	104.6	103.8	105.8

Incident Rates By Coating Type
Incidents Per 1,000 Mile Years



PE = Extruded Polyethylene
AM = Extruded Asphalt Mastic
Tape = Mill Applied Tape

FBE = Fusion Bonded Epoxy
Liquid = Epoxy Liquid Applied Systems
Butyl = Side Extruded Butyl Rudder

Bare (uncoated) lines, which comprised roughly 7% of the total, suffered the highest external corrosion and overall incident rates; in fact, these values were almost three times the average values for all pipelines included in the study. It should also be noted however, that these lines had the oldest mean year of pipe construction and a mean operating temperature higher than average.

The coal tar and asphalt enamel wrapped pipelines, about 5% of the total, had an external corrosion rate nearly as high as the bare pipelines. These lines were operated at an average of 8°F above the mean operating temperature; they were also on average 5 years newer than the mean.

Extruded asphalt mastic coated pipe, roughly one-quarter of the total, had the third highest external corrosion and overall incident rates. This pipe had the second oldest mean year of pipe construction and the lowest mean operating temperature.

Somewhat surprisingly, the 2% of the total pipe coated with fusion bonded epoxy had the forth highest external corrosion and overall incident rates. The external corrosion incident rate for this coating was slightly below the overall average. This pipe was the newest sample included in the study, with a 1984 mean year of pipe construction. However, the operating temperature was the highest of the group, 115.6°F.

Extruded polyethylene with asphalt mastic, liquid systems and mill applied tape had external corrosion incident rates roughly one-half to one-third the average. The overall incident rates for these coatings were also considerably lower than the average. The mean pipe age and mean operating temperatures varied considerably among these groups. However, the pipe was generally much newer than average, with higher than average operating temperatures.

The lowest incident rates were observed on pipe with extruded polyethylene with side extruded butyl, which comprised 8% of the total. The observed external corrosion and overall incident rates for these pipelines were both less than one-tenth the average values. This pipe sample was relatively new, with a 1973 mean year of pipe construction. The mean operating temperature was moderately high, 105.8°F.

Difficulties were encountered performing multiple logit regressions using the coating type as an independent leak indicator. This occurred because the leak data and pipe data were gathered separately. Subsequently, the data were compiled using two separate databases. The coating type data was gathered for each segment of each pipeline within the state, resulting in tens of thousands of individual pipe segments. However, the leak data contained only the pipeline identification on which the leak occurred, as well as other pertinent data; the leak data did not specifically identify which segment of pipe suffered the leak. As a result, some manipulation of the data was necessary to perform the multiple logit analysis. The resulting analysis did indicate a correlation between coating type and leak incident rates.

4.17 High Risk Pipelines

The California Government Code, §51013.5 (f) prescribes criteria for identifying certain pipelines as *high risk*. The Code also specifies additional requirements for pipelines identified as such. It should be noted that these requirements only apply to intrastate pipelines; interstate pipelines are not subject to these additional requirements. Basically, the regulation requires the following intrastate pipelines to be considered *high risk*:

- have suffered two or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion or defect in the prior three years,

- have suffered three or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion, defects, or external forces, but not all due to external forces, in the prior three years,

- have suffered a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or defect of more than 50,000 gallons, or 10,000 gallons in a standard metropolitan statistical area, in the prior three years; or have suffered a leak due to corrosion or defect which the State Fire Marshal finds has resulted in more than 42 gallons of a hazardous liquid within the State Fire Marshal's jurisdiction entering a waterway in the prior three years; or have suffered a reportable leak of a hazardous liquid with a flash point of less than 140°F in the prior three years,

- are less than 50 miles long, and have experienced a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or a defect in the prior three years, or

- have experienced a reportable leak in the prior five years due to corrosion or defect, except during a certified hydrostatic pressure test, on a section of pipe more than 50 years old.

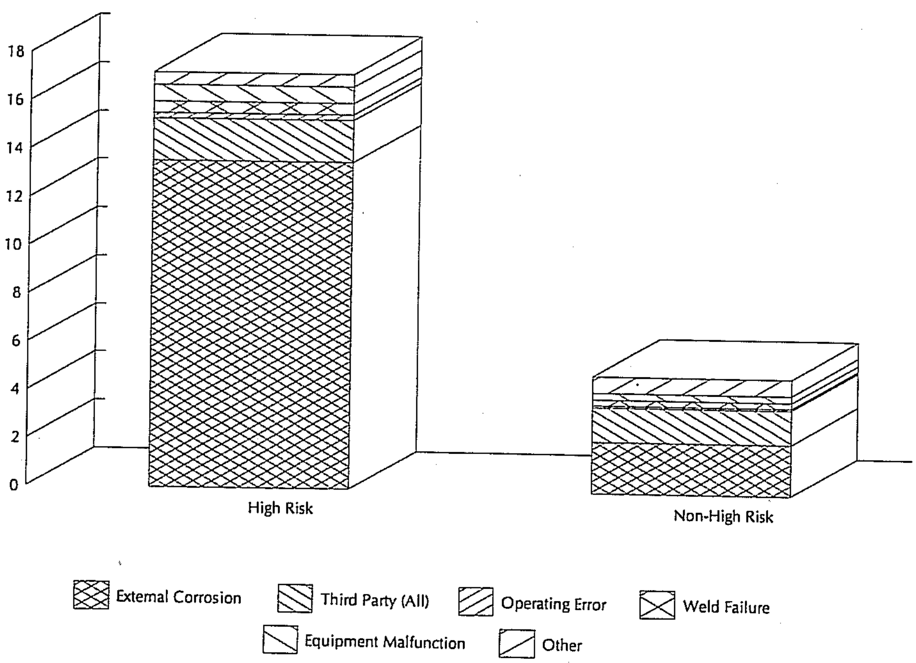
Intrastate pipelines meeting any of the above criteria, remain identified as *high risk* lines until 5 years pass without a reportable leak due to corrosion or defect. Basically these *high risk* pipelines must be hydrostatically tested every two years, instead of the generally required five year hydrostatic test interval for intrastate lines.

Table 4-17 presents the incident rate data for *high risk* versus non-*high risk* pipelines. The lines which were identified as *high risk* during our data gathering phase, were considered as *high risk* lines for the entire 10 year study period. By doing so, we were able to evaluate any resulting increase in pipeline safety.

Table 4-17
High Risk versus Non-High Risk Pipelines
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	High Risk		Non-High Risk	
	No. of Incidents	Incident Rate	No. of Incidents	Incident Rate
External Corrosion	176	13.54	125	2.16
Internal Corrosion	2	0.15	12	0.21
3rd Party - Construction	11	0.85	53	0.91
3rd Party Farm Equipment	3	0.23	15	0.26
3rd Party - Train Derailment	0	0.00	2	0.03
3rd Party - External Corrosion	5	0.38	2	0.03
3rd Party - Other	4	0.31	10	0.17
Human Operating Error	3	0.23	5	0.09
Design Flaw	1	0.08	1	0.02
Equipment Malfunction	9	0.69	18	0.31
Maintenance	1	0.08	4	0.07
Weld Failure	6	0.46	13	0.22
Other	3	0.23	22	0.38
Total	224	17.24	282	4.86
Number of Mile Years	12,996		58,002	
Average Year Pipe Constructed	1950		1958	
Average Operating Temperature (°F)	130		91	
Average Diameter (inches)	12.6		12.3	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



As indicated in Table 4-17, the present criteria has done a good job of identifying lines with higher than average incident rates. Specifically, the *high risk* pipelines had an overall incident rate three and one-half times greater than the non-*high risk* lines. The external corrosion incident rate for these lines was over six times the rate for the non-*high risk* pipelines. The leak incident rate for all incident causes, except external corrosion, were fairly consistent between the two groups, 3.70 versus 2.70 incidents per 1,000 mile years for *high risk* and non-*high risk* pipelines respectively.

Although the data presented in Table 4-17 indicates that the present criteria for identifying *high risk* pipelines has identified these lines reasonably well, there are undoubtedly exceptions. We recommend that the CSFM consider using the data collected in this study to identify *high risk* pipelines. The data could be sorted and a leak incident rate could be calculated for each pipeline included in the study. High risk lines could then be identified as those with leak incident rates above some predetermined figure. If pursued, consideration should be given to establishing different limits for product and crude pipelines, since the risk to public safety differ.

For example, *high risk* pipelines could be those with an overall leak incident rate say 50% higher than average for product lines and maybe 100% higher than average for crude lines. Using the values presented earlier in Table 4-4, this would result in incident rate identification criteria of 20 and 7 incidents per 1,000 mile years for crude and product systems respectively.

Table 4-17A shows the leak incident history for *high risk* pipelines during the ten year study period. As indicated, the external corrosion and overall rates fluctuated significantly during the study period.

A simple ordinary least squares line of best fit was determined using the overall leak data for high risk pipelines. The data indicated a slight reduction in the overall incident rate during the study period. However, the statistical *R squared* was an extremely low 0.02. As a result, we do not believe that there has been a measurable decrease in overall incident rates as a result of the *high risk* pipeline program. On the other hand, we did not see an increase, which one may have expected since the mean age of pipe increased during the study period.

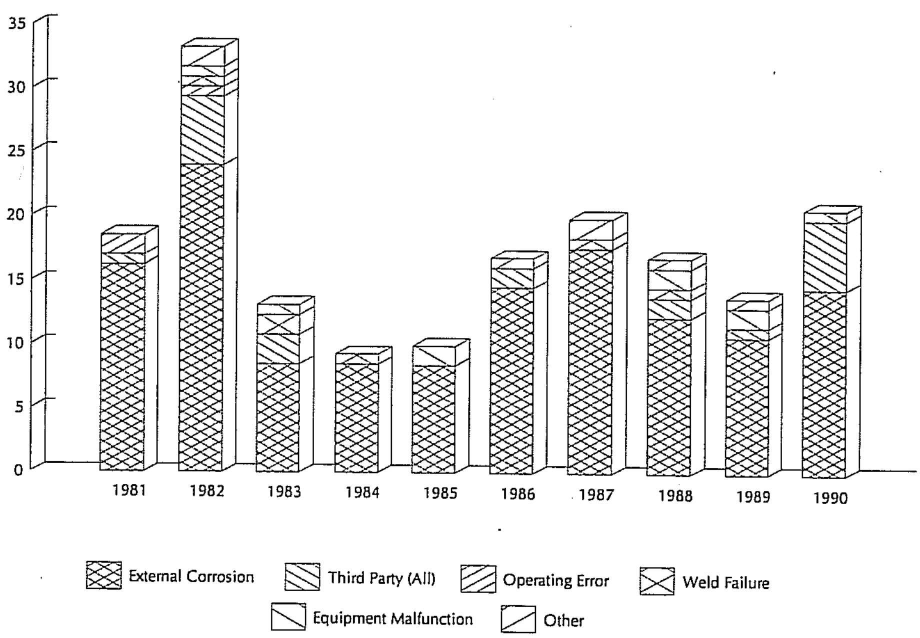
An ordinary least squares line of best fit was also prepared for *high risk* pipeline external corrosion leaks only. Once again, the data indicated a slight reduction in the external corrosion incident rate during the study period. But the resulting *R squared* was a very low 0.04. As a result, we do not believe that there has been a measurable decrease in external corrosion incident rates as a result of the *high risk* pipeline program. But as noted above, we did not see an increase either.

Similar analyses were also performed for leaks resulting from all causes except external corrosion, as well as for average spill sizes. Once again, these resulted in extremely low statistical *R squared* values. In all cases, we believe that the overall 10 year average values presented in Table 4-17 should be used.

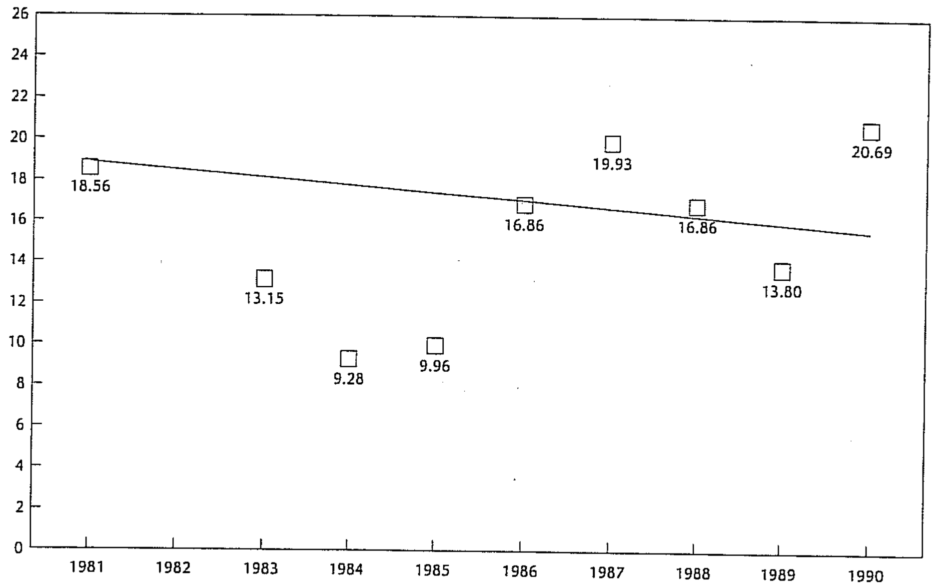
Table 4-17A
Incident Rates By Year of Study - High Risk Pipelines Only
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
External Corrosion	16.24	23.98	8.51	8.51	8.43	14.56	17.63	12.26	10.73	14.56
Internal Corrosion	0.00	0.00	0.00	0.00	0.00	0.00	1.53	0.00	0.00	0.00
3rd Party - Construction	0.00	4.64	0.77	0.00	0.00	0.00	0.00	0.77	0.77	1.53
3rd Party - Farm Equipment	0.00	0.00	0.77	0.00	0.00	0.77	0.00	0.77	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.83
3rd Party - Other	0.77	0.77	0.77	0.00	0.00	0.77	0.00	0.00	0.00	0.00
Human Operating Error	1.55	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00
Equipment Malfunction	0.00	0.77	0.77	0.00	1.53	0.00	0.00	1.53	1.53	0.77
Maintenance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00
Weld Failure	0.00	0.77	1.55	0.77	0.00	0.00	0.77	0.77	0.00	0.00
Other	0.00	1.55	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00
Total	18.56	33.26	13.15	9.28	9.96	16.86	19.93	16.86	13.80	20.69
Number of Mile Years	1,293	1,293	1,293	1,293	1,305	1,305	1,305	1,305	1,305	1,305
Mean Year Pipe Constructed	1949	1949	1949	1949	1950	1950	1950	1950	1950	1950
Mean Operating Temperature (°F)	131.0	131.0	131.0	130.9	130.4	130.4	130.4	130.4	130.4	130.4
Mean Diameter (inches)	12.6	12.6	12.6	12.6	12.6	12.5	12.6	12.6	12.6	12.6
Average Spill Size (barrels)	159.4	410.1	742.6	660.5	722.2	673.6	631.5	569.2	538.6	486.0
Average Damage ($1,000 US 1983)	5.5	22.3	74.4	72.3	95.4	130.8	108.7	100.4	92.8	91.4

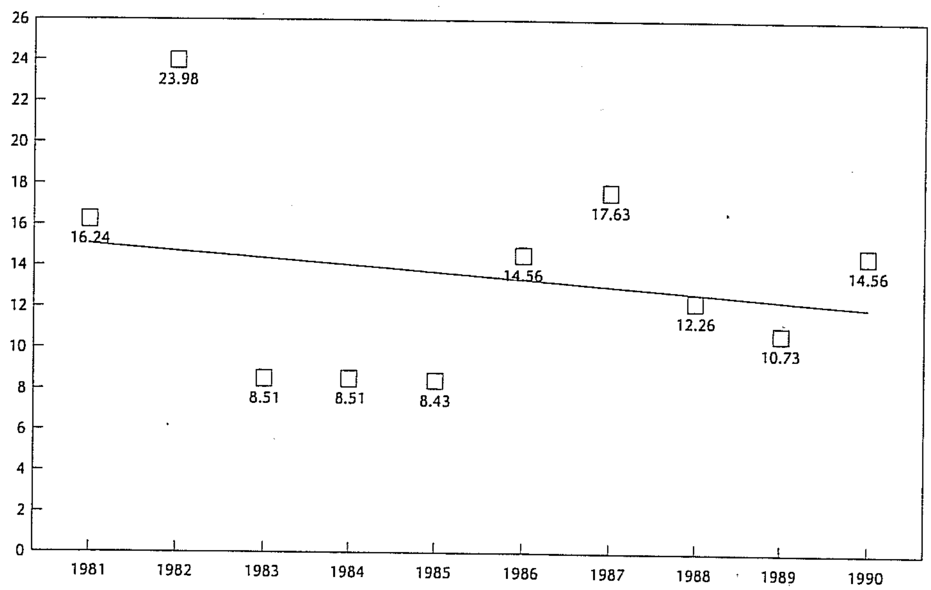
High Risk Pipeline Incident Rates By Year of Study
Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
High Risk Pipeline Overall Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

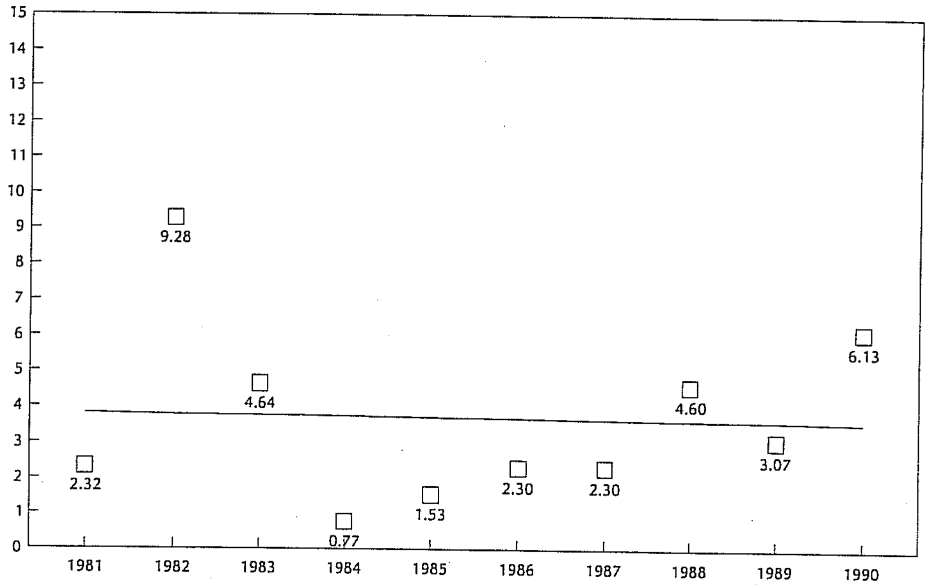


Ordinary Least Squares Line of Best Fit
High Risk Pipeline External Corrosion Incident Rates By Year of Study
Incidents Per 1,000 Mile Years

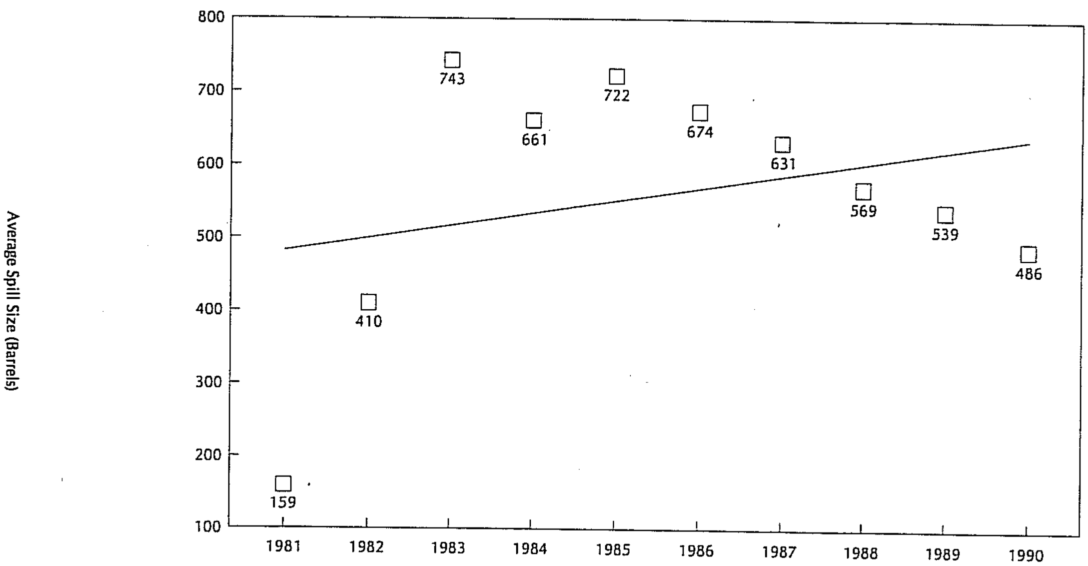


Ordinary Least Squares Line of Best Fit
High Risk Pipeline Incident Rates For Other Causes By Year of Study
(Excludes All External Corrosion Incidents)

Incidents Per 1,000 Mile Years



Ordinary Least Squares Line of Best Fit
High Risk Pipeline Average Annual Spill Size (Barrels) By Year of Study



Considering the lack of a clear reduction in incident rates during the study period for *high risk* pipelines, it may be worthwhile to reconsider the requirements for these lines to more effectively reduce the likelihood of leaks. It does not appear as though the increased hydrostatic testing requirements have resulted in significant benefits. Since the vast majority of these leaks were caused by external corrosion, more benefits could likely be obtained by redirecting the monies currently expended on additional hydrostatic testing to other activities aimed at reducing external corrosion leaks (e.g. pipeline replacements, recoating, cathodic protection system upgrades, etc.).

The American Petroleum Institute conducted a survey of interstate pipeline operators in 1986-87. They found that the average cost of hydrostatic testing was $5,300 per mile. Using this figure and considering the roughly 1,300 miles of line in the current *high risk* inventory, at least $2,000,000 per year would be available to be redirected toward actions intended to prevent leaks. This would result from eliminating the current increased hydrostatic testing requirements for *high risk* lines.

4.18 Internal Inspections

During the last several years, there have been significant advances in the technologies available to internally inspect pipelines using *smart* pigs. These tools use several technologies to identify wall thinning, buckling, erosion, corrosion and other anomalies. These technologies, available from various vendors, differ greatly in their ability to identify and quantify various forms of damage and/or deterioration. Some are extremely precise and sophisticated, while others are much more general.

Unfortunately, most of these inspection tools are rather long. As a result, they require smooth, long radius bends to facilitate their passage; most will not traverse short radius elbows for example.

Out of the roughly 7,800 miles of regulated California pipelines, nearly 58% (4,495 miles) are capable of being inspected using these techniques, with little or no modification. 70% (3,128 miles) of these pipelines, which are capable of being inspected, have already been inspected in this manner.

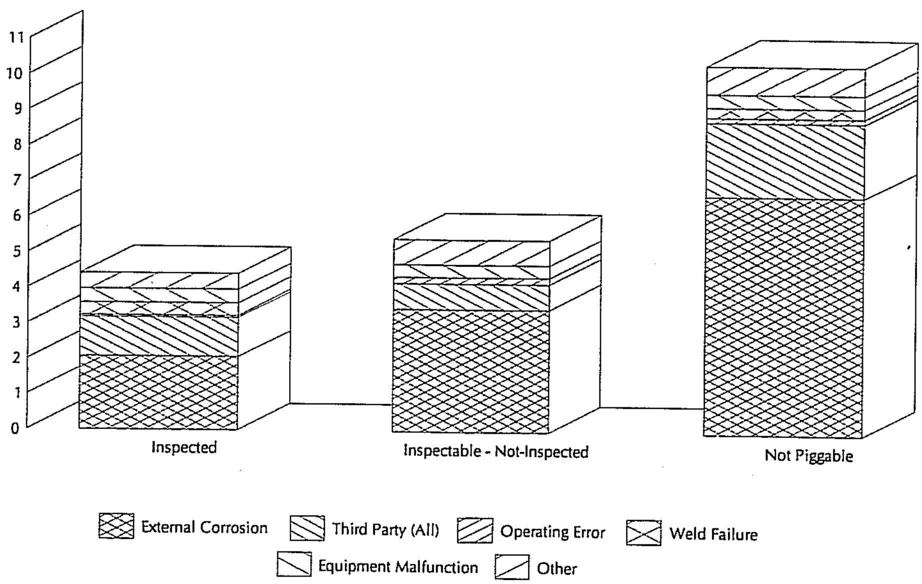
Table 4-18 presents a comparison of the incident rates for pipelines meeting three criteria:

- pipelines which have been internally inspected,
- pipelines which could be inspected with little or no modification, but had not been inspected by the end of the study period, and
- those pipelines which are not capable of passing an inspection pig without significant modification.

Table 4-18
Incidents By Internal Inspections
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Internally Inspected		Inspectable Not-Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	65	2.06	39	3.47	198	6.70
Internal Corrosion	2	0.06	0	0.00	12	0.41
3rd Party - Construction	16	0.51	6	0.53	42	1.42
3rd Party Farm Equipment	8	0.25	0	0.00	10	0.34
3rd Party - Train Derailment	1	0.03	1	0.09	0	0.00
3rd Party - External Corrosion	2	0.06	0	0.00	5	0.17
3rd Party - Other	8	0.25	1	0.09	5	0.17
Human Operating Error	2	0.06	2	0.18	4	0.14
Design Flaw	1	0.03	0	0.00	1	0.03
Equipment Malfunction	12	0.38	4	0.36	11	0.37
Maintenance	3	0.10	0	0.00	2	0.07
Weld Failure	11	0.35	0	0.00	8	0.27
Other	8	0.25	8	0.71	9	0.30
Total	139	4.41	61	5.42	307	10.39
Number of Mile Years	31,500		11,253		29,550	
Percentage of Total Mile Years	43.6%		15.6%		40.9%	
Total Length (Miles)	3,128		1,367		3,305	
Percentage Total Length	40.1%		17.5%		42.4%	
Mean Year Pipe Constructed	1963		1941		1944	
Mean Operating Temperature (°F)	121		148		97	
Mean Diameter (inches)	15.3		13.0		8.7	

Incident Rate Comparison
Incidents Per 1,000 Mile Years



The data indicates that pipe which had been internally inspected had the lowest leak incident rate. However, this pipe was also the newest of any category, with a 1963 mean year of pipe construction, 6 years newer than average. This pipe was also operated at a mean operating temperature of 121°F, 23°F higher than average and had the highest mean pipe diameter, 15.3".

It is also interesting to compare the two categories of pipe which had not been internally inspected. Although the pipe which was not inspection piggable was newer and operated at a lower mean operating temperature, it had an overall incident rate almost double the rate for piggable pipe which had not been inspected. However, the mean diameter for non-piggable lines was much smaller, 8.7" versus 13.0".

4.19 Seasonal Effects

The possibility of incident rate variations throughout the year exist for many causes. For example, heavy winter rains could result in increased external corrosion leaks during the winter. Also, heavy summer construction activity could increase third party damage during this period. In an attempt to evaluate any such seasonal variations, the leak data was sorted by month of occurrence. This data is presented in Table 4-19.

Most of the leak causes appeared to have rather random variations throughout the year. Also, the limited data available for most causes made it difficult to identify any trends. However, the following points were worth noting:

- Third party damage from farm equipment did not occur from April through August during the entire 10 year study period.

- The overall leak incident rate was lowest from April through June.

4.20 Leaking Component

Table 4-20 presents a break-down of the items which leaked, by cause, for each incident included in the study. As noted, nearly 87% of all leaks occurred in the pipe body itself. Valves were responsible for another 3.1% of the incidents. 2% were caused by longitudinal weld seam failures in the pipe body. 1.6% were caused by leaks at welded fittings. The remaining 6.7% of the leaks were from various other causes.

Table 4-19
Incident Rates By Month of Year
(Incidents Per 1,000 Mile Years)

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	3.65	3.49	4.98	3.15	3.15	3.82	5.64	3.15	3.65	3.49	5.97	6.31
Internal Corrosion	0.33	0.17	0.17	0.17	0.00	0.33	0.33	0.17	0.00	0.33	0.33	0.00
3rd Party - Construction	0.50	0.83	0.50	1.00	0.50	0.50	1.66	0.83	0.83	1.66	1.16	0.83
3rd Party - Farm Equipment	0.66	0.33	0.33	0.00	0.00	0.00	0.00	0.00	0.17	1.00	0.33	0.17
3rd Party - Train Derailment	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.17
3rd Party - External Corr	0.00	0.00	0.17	0.17	0.00	0.17	0.00	0.17	0.00	0.17	0.17	0.17
3rd Party - Other	0.17	0.33	0.83	0.17	0.00	0.00	0.17	0.00	0.00	0.17	0.00	0.50
Human Operating Error	0.00	0.00	0.17	0.00	0.00	0.50	0.00	0.17	0.00	0.17	0.33	0.00
Design Flaw	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.17	0.00
Equipment Malfunction	0.33	0.83	0.33	0.00	0.33	0.17	0.33	1.00	0.17	0.33	0.17	0.50
Maintenance	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.17	0.17	0.17	0.17	0.00
Weld Failure	0.33	0.66	0.33	0.33	0.00	0.17	0.17	0.33	0.17	0.33	0.17	0.17
Other	0.33	0.50	0.17	0.50	0.17	0.00	0.50	0.50	0.33	0.50	0.50	0.33
Total	6.31	7.30	7.97	5.48	4.32	5.64	8.80	6.64	5.48	8.30	9.46	9.13

Incident Rates By Month of Year
Incidents Per 1,000 Mile Years

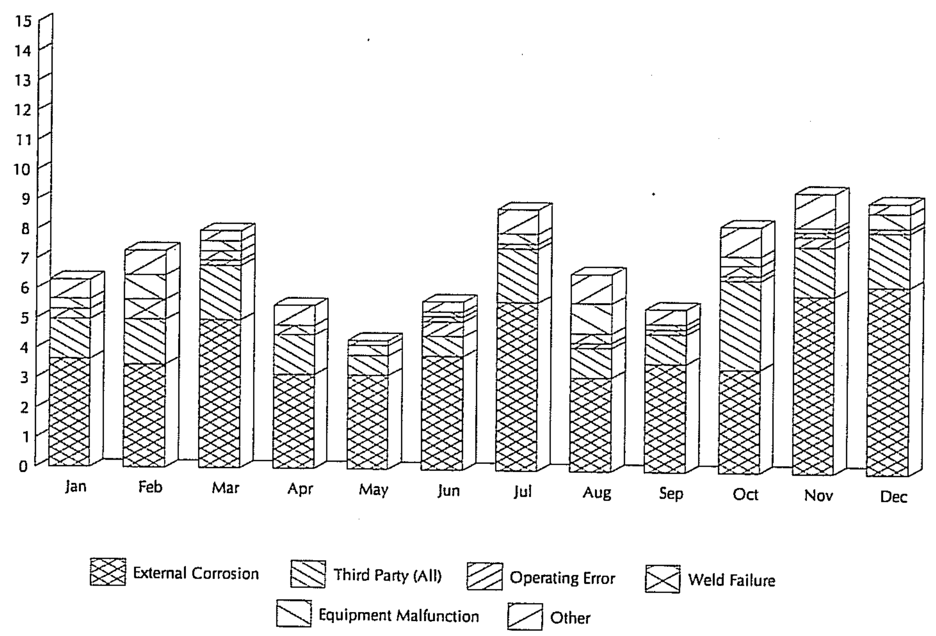
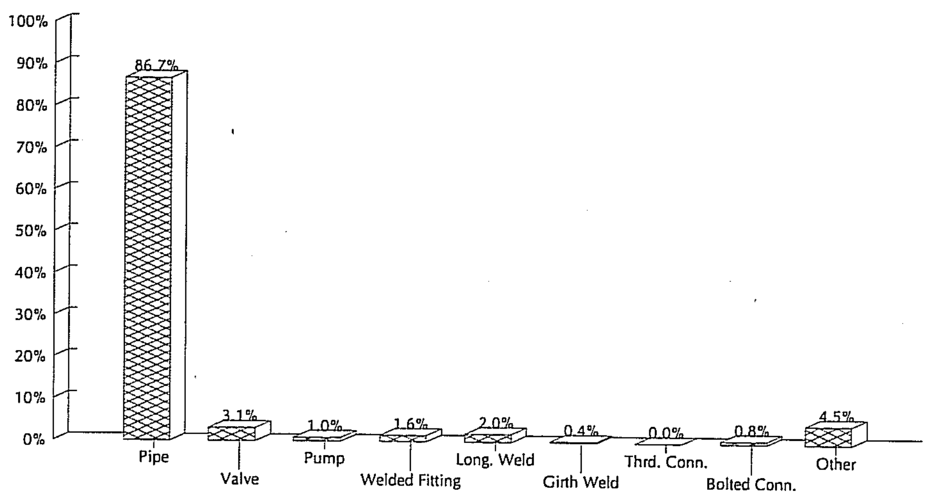


Table 4-20
Incidents by Item Which Leaked, by Cause

Leak Cause	Pipe No.	Pipe %	Valve No.	Valve %	Pump No.	Pump %	Welded Fitting No.	Welded Fitting %	Long. Weld No.	Long. Weld %
External Corrosion	298	67.3	0	0.0	0	0.0	0	0.0	0	0.0
Internal Corrosion	14	3.2	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Construction	62	14.0	2	12.5	0	0.0	1	12.5	0	0.0
3rd Party - Farm Equipment	18	4.1	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Train Derailment	2	0.5	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - External Corrosion	7	1.6	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Other	13	2.9	0	0.0	0	0.0	1	12.5	0	0.0
Human Operating Error	5	1.1	1	6.3	0	0.0	1	12.5	0	0.0
Design Flaw	0	0.0	1	6.3	0	0.0	1	12.5	0	0.0
Equipment Malfunction	6	1.4	5	31.3	2	40.0	0	0.0	1	10.0
Maintenance	1	0.2	3	18.8	0	0.0	0	0.0	0	0.0
Weld Failure	4	0.9	0	0.0	0	0.0	4	50.0	8	80.0
Other	13	2.9	4	25.0	3	60.0	0	0.0	1	10.0
Total	443	100.0	16	100.0	5	100.0	8	100.0	10	100.0

Leak Cause	Girth Weld No.	Girth Weld %	Thread Conn No.	Thread Conn %	Bolted Conn No.	Bolted Conn %	Other No.	Other %
External Corrosion	2	100.0	0	0.0	0	0.0	4	17.4
Internal Corrosion	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Construction	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Farm Equipment	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Train Derailment	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - External Corrosion	0	0.0	0	0.0	0	0.0	0	0.0
3rd Party - Other	0	0.0	0	0.0	0	0.0	0	0.0
Human Operating Error	0	0.0	0	0.0	0	0.0	1	4.3
Design Flaw	0	0.0	0	0.0	0	0.0	0	0.0
Equipment Malfunction	0	0.0	0	0.0	0	0.0	13	56.5
Maintenance	0	0.0	0	0.0	1	25.0	0	0.0
Weld Failure	0	0.0	0	0.0	0	0.0	3	13.0
Other	0	0.0	0	0.0	3	75.0	2	8.7
Total	2	100.0	0	0.0	4	100.0	23	100.0



4.21 Hydrostatic Testing Interval

The hydrostatic testing requirements for intrastate and interstate pipelines vary significantly. Basically, the regulations for intrastate lines require periodic hydrostatic testing while those for interstate lines generally require only initial hydrostatic testing. Specifically, the California Government Code §51013.5 requires hydrostatic testing of intrastate pipelines as follows:

- Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance, shall be tested in accordance with 49 CFR 195, Subpart E.

- Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and not provided with effective cathodic protection shall be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and provided with effective cathodic protection shall be hydrostatically tested every five years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be tested every two years.

- Piping within a refined products bulk loading facility shall be tested every five years for those pipelines with effective cathodic protection and every three years for those pipelines without effective cathodic protection.

For interstate pipelines, 49 CFR 195.300 requires hydrostatic testing of newly constructed pipelines; existing steel pipeline systems that are relocated, replaced, or otherwise changed; onshore steel interstate pipelines constructed before January 8, 1971, that transport highly volatile liquids; and onshore steel intrastate pipelines constructed before October 21, 1985, that transport highly volatile liquids.

Data was gathered to facilitate an evaluation of hydrostatic testing effectiveness. Two separate pieces of information were gathered. First, the total number of hydrostatic tests performed on each pipeline during the ten year study period was gathered. Secondly, for each leak which occurred during the study period, the date of the preceding hydrostatic test was obtained.

To determine the average hydrostatic test interval for each pipeline during the study period, the ten year study period was divided by the total number of hydrostatic tests performed during the study period. Incident rates were then determined for each pipeline within given ranges of hydrostatic testing intervals. Table 4-21 presents the resulting data. As indicated, the pipelines which were hydrostatically tested most frequently, up to two years average hydrostatic test interval, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase the incident rate.

On the other end of the spectrum, the lines which had the longest average hydrostatic test interval suffered the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. Once again, these factors would tend to decrease their incident rates as we have already seen.

California's *high risk* pipeline category would also tend to skew this data. As previously mentioned, these lines had a generally much higher leak incident rate. Those which were greater than 10 years old were required to be tested at either one or two year intervals, depending on whether or not they were cathodically protected.

Table 4-21A presents the second set of data; the time since hydrostatic testing for each leak, regardless of cause. Although not as drastic, this analysis resulted in similar results. As indicated, the pipelines which had the shortest interval between hydrostatic testing and the leak, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase incident rates.

On the other hand, the lines which had the greatest length of time between hydrostatic testing and the subsequent leak, had the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. These factors would decrease their incident rates as we have already seen.

With the data presented, it is difficult to readily determine the effectiveness of hydrostatic testing. The multiple regressions indicated that pipe age and operating temperatures had the greatest impact on leak incident rates. We believe that the data presented in this subsection reflected the pipe age and operating temperature effects. From this data alone, it is impossible to determine whether or not more frequent hydrostatic testing affected the frequency of leak incidents. However, the data presented in section 4-17 regarding *high risk* pipelines did not indicate a statistical relationship between more frequent hydrostatic testing intervals for *high risk* lines during the latter portion of the study period and resulting reduced incident rates. In other words, it did not appear that more frequent hydrostatic testing reduced leak incident rates. As a result, consideration should be given to increasing the hydrostatic test intervals on some frequently tested lines and redirecting these monies to work which would reduce external corrosion (e.g. internal inspection, close interval cathodic protection surveys, etc.).

Table 4-21
Average Hydrostatic Testing Interval During Study Period
Incident Rate Comparison

(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate
External Corrosion	144	9.58	113	4.67	36	2.06
Internal Corrosion	6	0.40	6	0.25	0	0.00
3rd Party - Construction	21	1.40	15	0.62	16	0.92
3rd Party Farm Equipment	0	0.00	6	0.25	11	0.63
3rd Party - Train Derailment	0	0.00	0	0.00	1	0.06
3rd Party - External Corrosion	2	0.13	4	0.17	0	0.00
3rd Party - Other	5	0.33	2	0.08	0	0.00
Human Operating Error	5	0.33	3	0.12	0	0.00
Design Flaw	0	0.00	1	0.04	0	0.00
Equipment Malfunction	12	0.80	9	0.37	4	0.23
Maintenance	0	0.00	3	0.12	0	0.00
Weld Failure	3	0.20	10	0.41	2	0.11
Other	3	0.20	12	0.50	4	0.23
Total	201	13.37	184	7.61	74	4.24
Number of Mile Years	15,032		24,173		17,449	
Mean Year Pipe Constructed	1949		1953		1959	
Mean Operating Temperature (°F)	122.3		104.6		88.5	
Mean Diameter (Inches)	11.4		12.7		12.3	

Incident Rate Comparison

Incidents Per 1,000 Mile Years

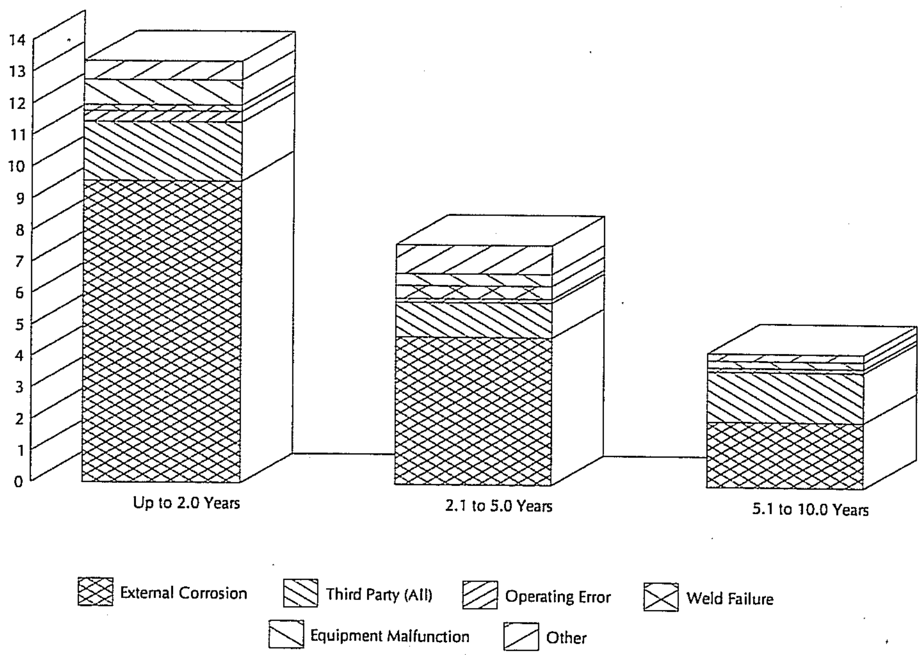
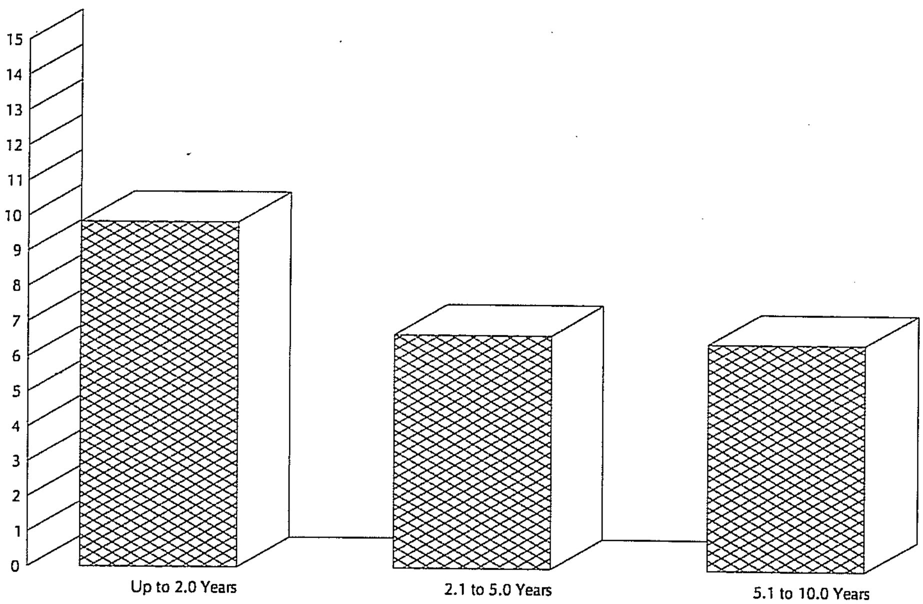


Table 4-21A
Time Since Last Hydrostatic Test At Time of Leak
Incident Rate Comparison
(Incidents Per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 to 5.0 Years		5.1 to 10.0 Years	
	Total No.	Rate	Number	Rate	Number	Rate
Total	147	9.83	165	6.67	109	6.46
Number of Mile Years	14,953		24,745		16,876	
Mean Year Pipe Constructed	1949		1953		1959	
Mean Operating Temperature (°F)	122.3		104.6		88.5	
Mean Diameter (Inches)	11.4		12.7		12.3	

Time Since Last Hydrostatic Test At Time of Leak
Incident Rate Comparison - All Causes
Incidents Per 1,000 Mile Years



Time Since Last Hydrostatic Test At Time of Leak

We also attempted to evaluate the effectiveness of hydrostatic testing by gathering data regarding the number of leaks which occurred during hydrostatic testing. Unfortunately however, the pipeline operators did not have consistent records for these leaks. Some operators had partial records for leaks which occurred during testing; but most operators did not have any records at all for these leaks. As a result, it was impossible to complete an analysis using this data.

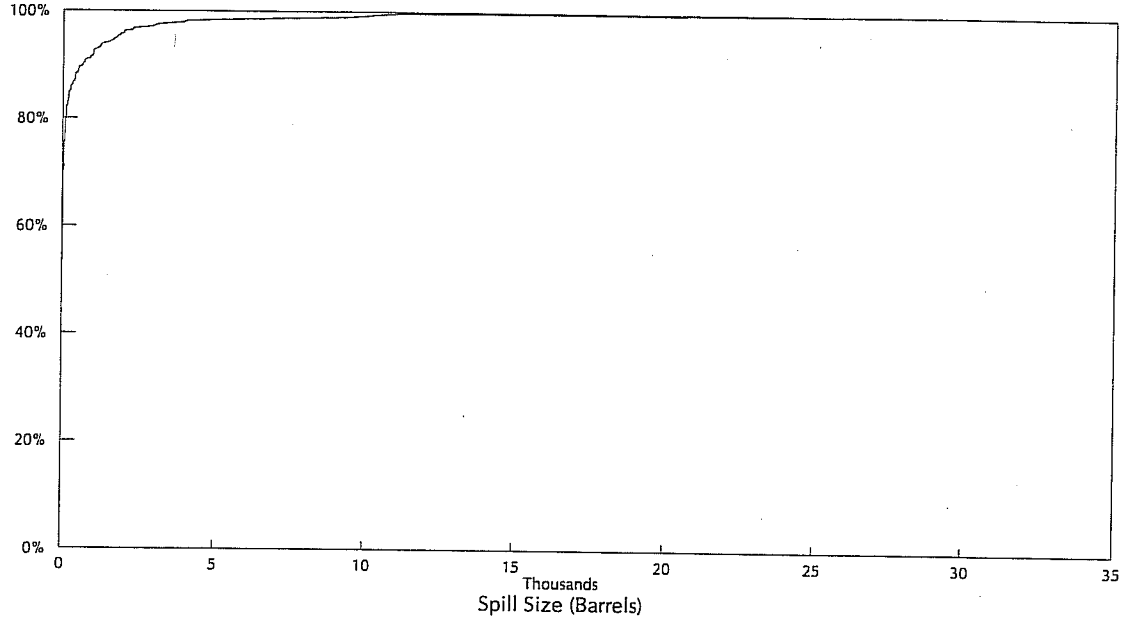
4.22 Spill Size Distribution

The spill size distribution for the leak sample is presented in Tables 4-22 and 4-22A. The coordinates of a few selected points along the curve are summarized below:

- 27% of the incidents resulted in spill volumes of one barrel or less.
- The median spill volume was five barrels.
- 61% of the incidents resulted in spill volumes of 10 barrels or less.
- 67% of the incidents resulted in spill volumes of 25 barrels or less.
- 82% of the incidents resulted in spill volumes of 100 barrels or less.
- 90% of the incidents resulted in spill volumes of 650 barrels or less.
- 95% of the incidents resulted in spill volumes of 1750 barrels or less.
- The largest spill volume was 31,000 barrels.

The huge difference between the 5 barrel median spill size and the 408 barrel mean spill size was caused by a relatively small number of incidents which resulted in large spill volumes. This increased the mean value considerably.

Table 4-22
Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents



Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents
0 to 100 Barrels Only

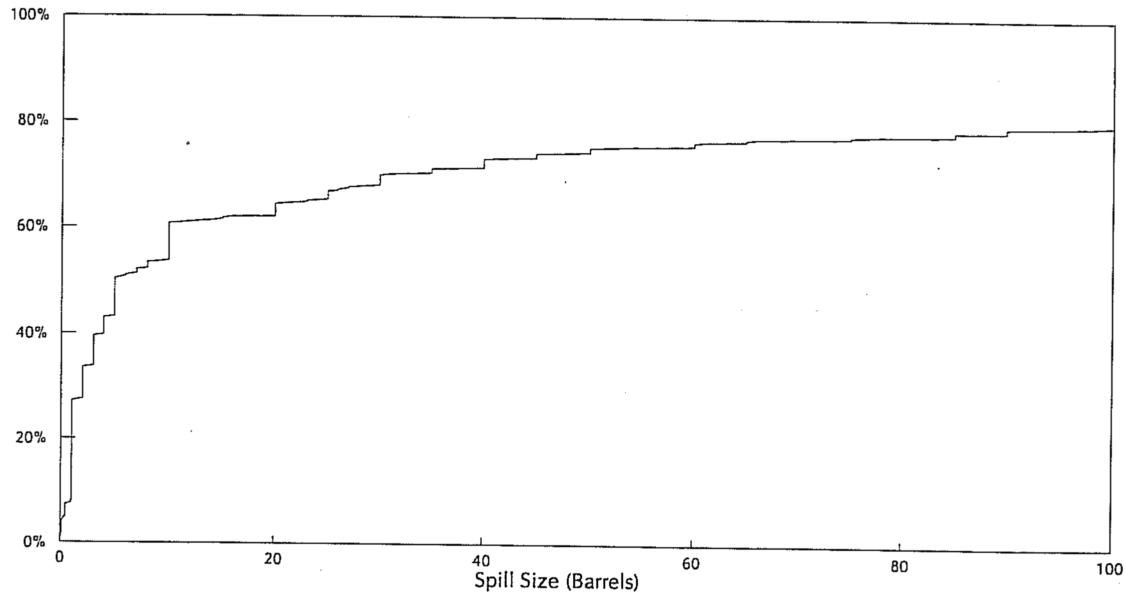
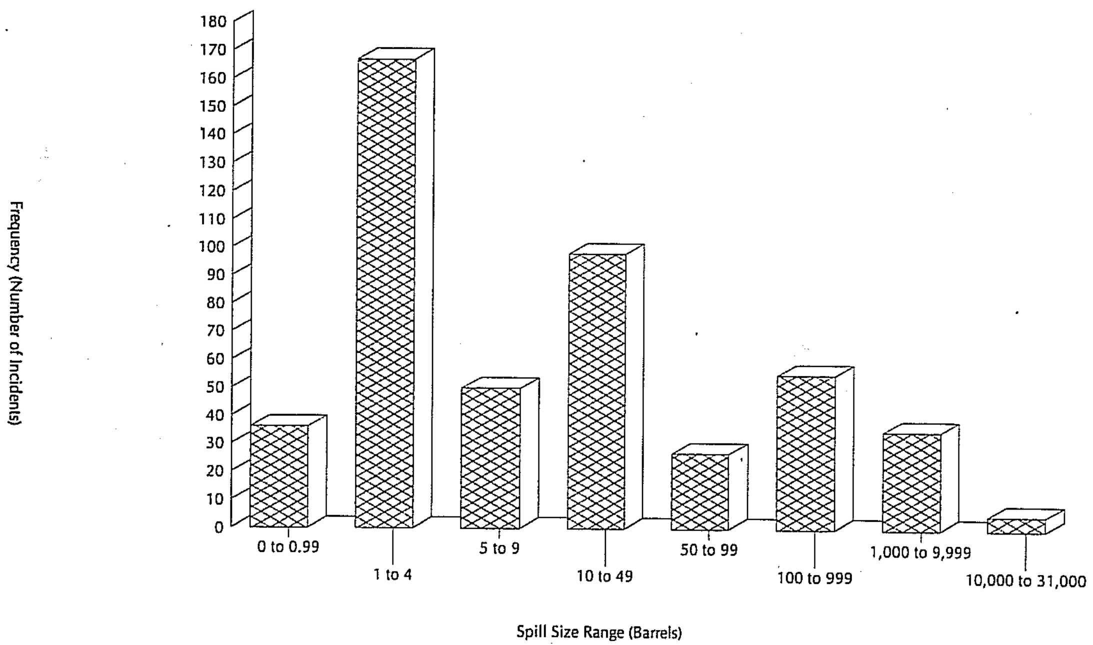


Table 4-22A
Spill Size Distribution

Spill Size (Barrels)	No. of Incidents	Percentage (%)	Cumulative %
0 to 0.99	36	7.61%	7.61%
1 to 4	167	35.31%	42.92%
5 to 9	50	10.57%	53.49%
10 to 49	98	20.72%	74.21%
50 to 99	27	5.71%	79.92%
100 to 999	55	11.63%	91.54%
1,000 to 9,999	35	7.40%	98.94%
10,000 to 31,000	5	1.06%	100.00%
Total	473		

Spill Size Distribution



4.23 Damage Distribution

The property damage distribution was very similar to the spill size distribution discussed in the preceding section; a few incidents resulted in relatively large property damage values which increased the mean value considerably. To the greatest extent possible, the damage figures included in this study included all costs associated with the incident (e.g. value of spilled fluid, clean-up, injury, judgements, fatalities, etc.).

Table 4-23 depicts this data graphically. All data has been shown in constant 1983 U.S. dollars. The values for each year were converted to 1983 constant dollars using the U.S. City average Consumer Price Indices as published by the U.S. Bureau of Labor Statistics. A few points along the curve are presented below:

- 25% of the incidents resulted in damages of $1,300 or less.
- The median damage was $7,200 per incident.
- 75% of the incidents resulted in damages of $38,000 or less.
- 90% of the incidents resulted in damages of $180,000 or less.
- 95% of the incidents resulted in damages of $590,000 or less.
- The largest reported damage for a single incident was $11,800,000. However, we understand that this figure may increase as additional claims are settled.

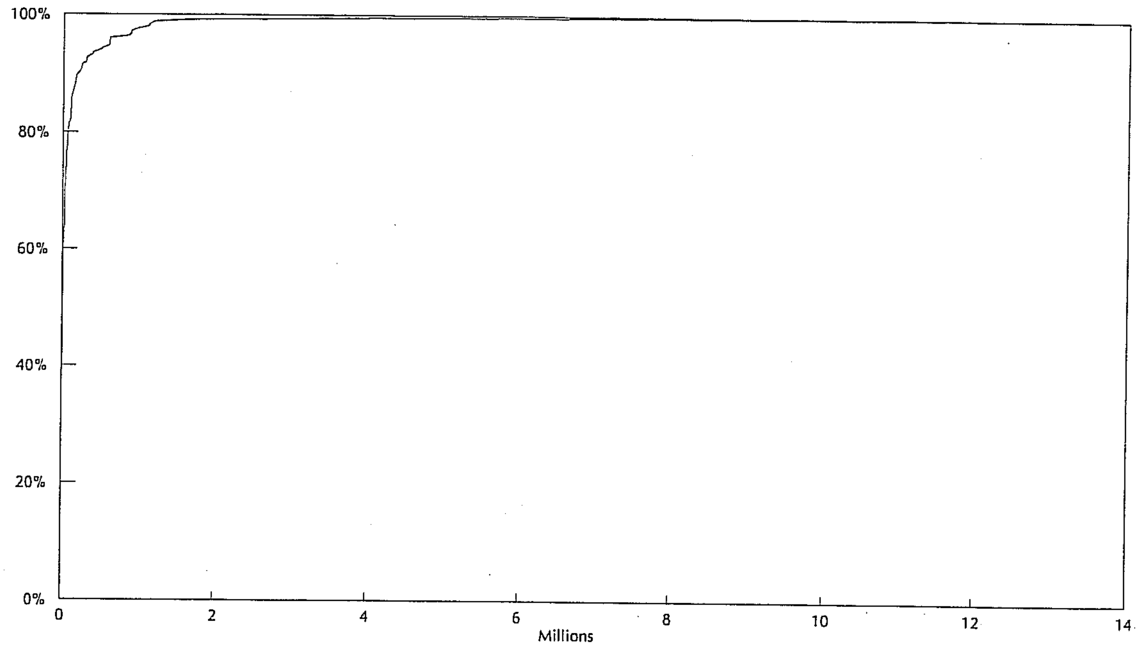
4.24 Stress Level Distribution

On 339 out of the total 514 leaks, sufficient data was available to calculate the stress level of the pipe at the leak site. The stress level, as a percentage of the pipe specified minimum yield strength, was determined using the following equation:

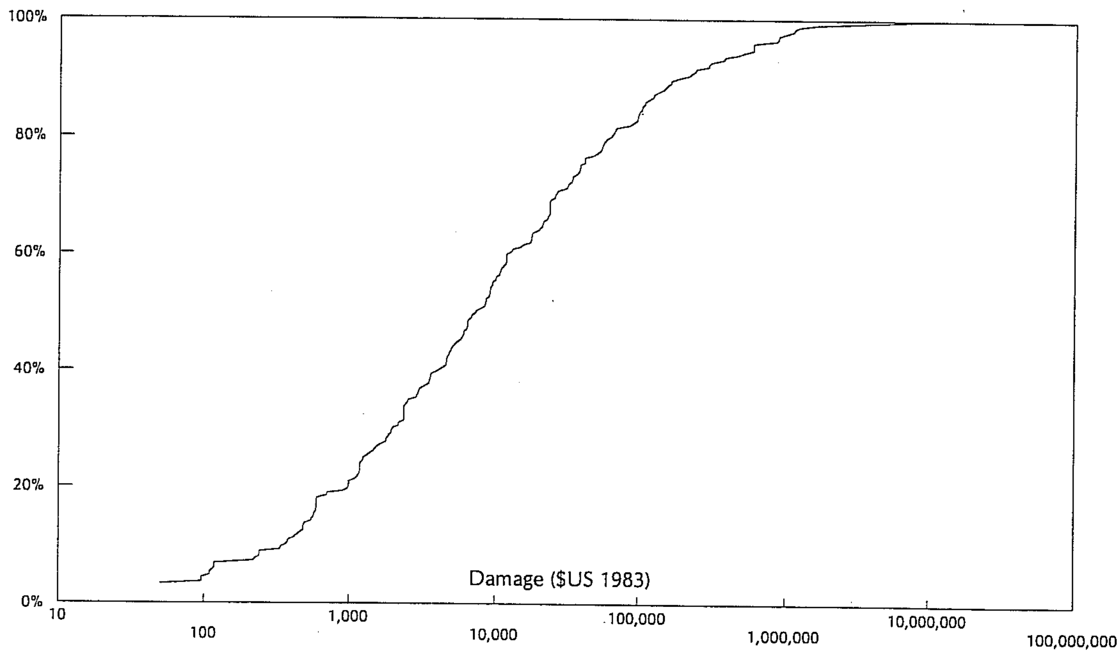
$$\% \text{ SMYS} = \{(P * D) \div (2 * t)\} \div \text{SMYS}$$

where: P = normal operating pressure (pounds per square inch)
D = outside pipe diameter (inches)
t = pipe wall thickness (inches)
SMYS = specified minimum yield strength of pipe which suffered the leak incident (psi)

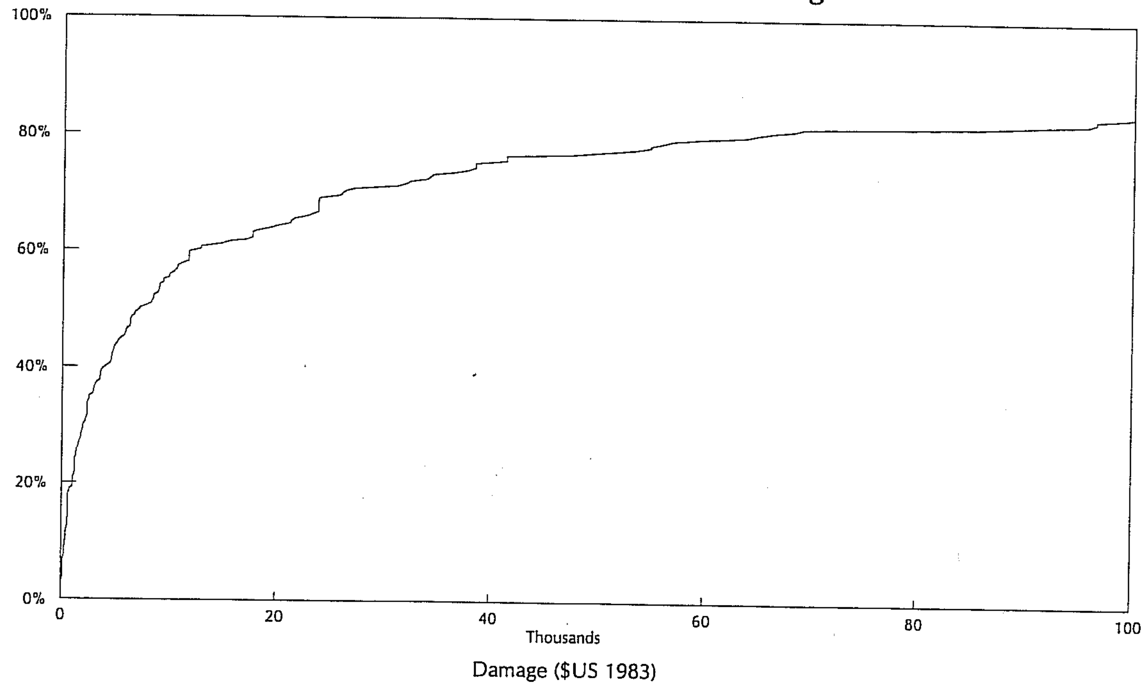
Table 4-23
Damage Distribution
Includes All Leaks With Property Damage Data



Damage Distribution - Logarithmic Scale



Damage Distribution - Selected Range



The cumulative percentage of the total leaks has been plotted versus the operating stress level in Table 2-24. As indicated, the median value for these leaks was relatively low, 24% SMYS. Also, from the shape of the curve we can see that the steepest portion occurred at the lower stress levels. The curve then flattened as the stress level increased.

However, one should be cautious about drawing conclusions from this data. Since some pipelines had literally thousands of pipe sections, all operating at different stress levels, it was impossible to develop an inventory of pipe operating at each stress level. Without this inventory, it was impossible to develop meaningful incident rates, as developed for other parameters. However, although not necessarily directly related, we did find in Section 4-15 that there was not a correlation between operating pressure and leak incident rates.

4.25 Injuries and Fatalities

The number of injuries and fatalities which resulted from incidents on California's regulated hazardous liquid pipeline systems during the study period are presented in Tables 4-25 and 4-25A. As indicated, nearly 94% of the injuries and all of the fatalities resulted from only three incidents; it is remarkable that just over one-half percent of the total incidents resulted in all of the fatalities and nearly all of the injuries during the entire ten year study period. These incidents are briefly described below:

- May 25, 1989, San Bernardino - On May 12, 1989, a freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board determined that during the derailment, and later during the movement of heavy equipment to remove the wreckage, the high-pressured products pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spilled over 300,000 gallons of gasoline into the neighborhood. The spilled fluid ignited and caused significant fire damage. This incident resulted in two fatalities and thirty-one injuries.

- February 22, 1986, Placer County - During the removal of an abandoned section of pipeline which had been relocated around a collapsed railroad trestle, approximately one barrel of gasoline was spilled. The fuel was ignited by a torch being used by the railroad's welding crew. As a result of the ignition, three welders jumped from the bridge into the creek below. This incident resulted in one fatality and one injury.

Table 4-24
Stress Level Distribution
At Incident Location

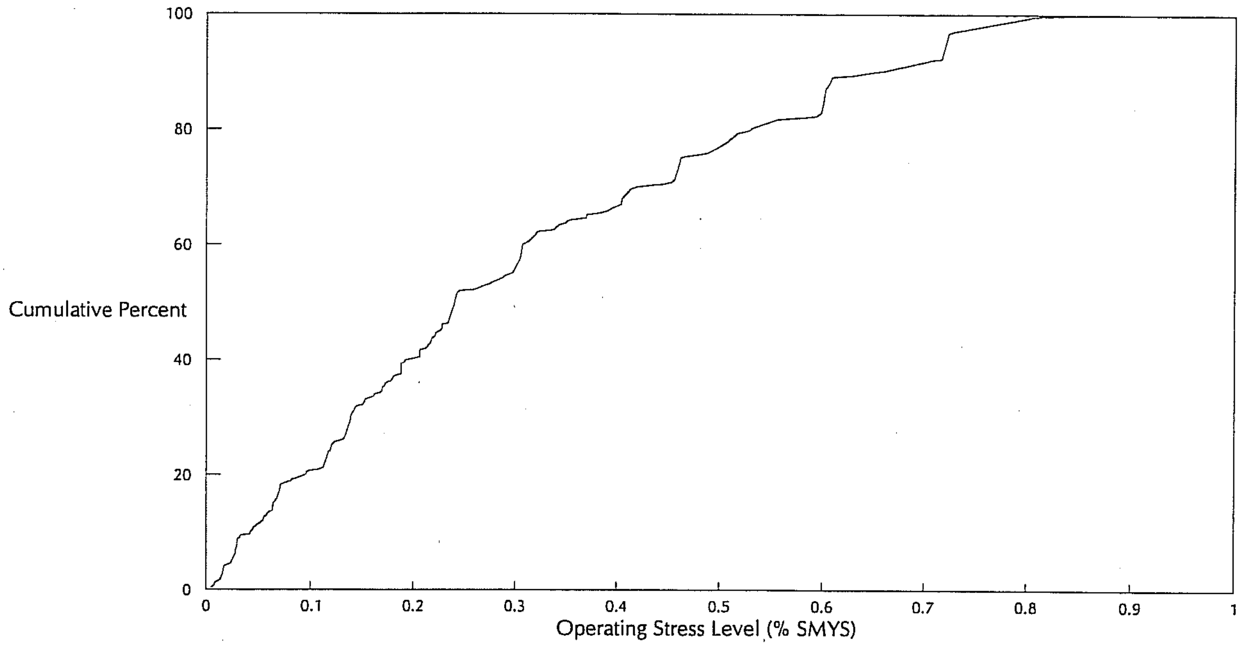
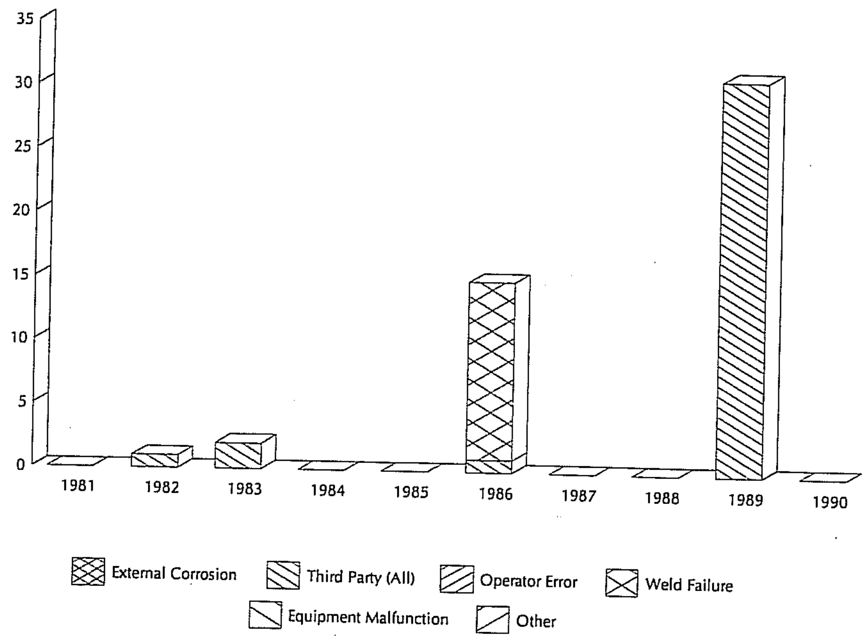


Table 4-25
Injuries By Year Of Study - By Cause
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Total
External Corrosion	0	0	0	0	0	0	0	0	0	0	0
Internal Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Construction	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Farm Equipment	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Train Derailment	0	0	0	0	0	0	0	0	31	0	31
3rd Party - External Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Other	0	1	2	0	0	1	0	0	0	0	4
Human Operating Error	0	0	0	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	0	0	0	0
Weld Failure	0	0	0	0	0	14	0	0	0	0	14
Other	0	0	0	0	0	0	0	0	0	0	0
Total	0	1	2	0	0	15	0	0	31	0	49

Injuries By Year of Study

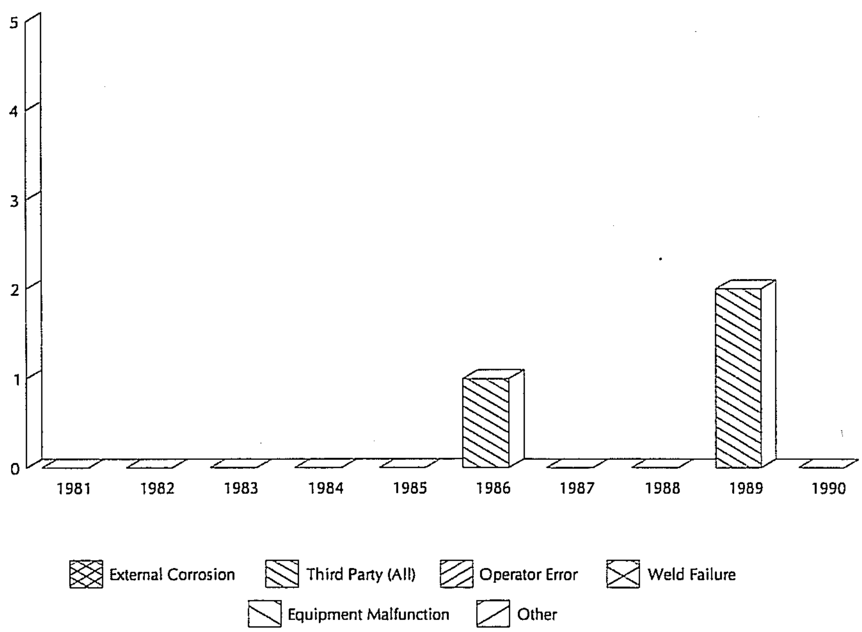


Note: The injury data presented above includes all injuries, regardless of severity; in some cases, incidents which only envolved on-site treatment are included. The reader should be cautioned from drawing any potentially misleading conclusions when comparing this data to that available from other sources.

Table 4-25A
Fatalities By Year Of Study - By Cause
(Incidents Per 1,000 Mile Years)

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	Total
External Corrosion	0	0	0	0	0	0	0	0	0	0	0
Internal Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Construction	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Farm Equipment	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Train Derailment	0	0	0	0	0	0	0	0	2	0	2
3rd Party - External Corrosion	0	0	0	0	0	0	0	0	0	0	0
3rd Party - Other	0	0	0	0	0	1	0	0	0	0	1
Human Operating Error	0	0	0	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	0	0	0	0	0
Maintenance	0	0	0	0	0	0	0	0	0	0	0
Weld Failure	0	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	1	0	0	2	0	3

Fatalities By Year of Study



- November 22, 1986, Tustin - A 10" API 5L X52, ERW pipe longitudinal weld seam ruptured. This resulted in a roughly 11,000 barrel unleaded gasoline spill. Fortunately, the spill did not result in fire or an explosion. The DOT Form 7000-1 filed with the Department of Transportation indicated that there were no injuries or fatalities meeting their reporting criteria. (See also Section 3.0 of this report.) However, 14 individuals were treated for symptoms consistent with hydrocarbon exposure. Eight fire personnel were treated at a medical facility, four fire personnel and one civilian were treated and released at the scene, and one fire department equipment operator was hospitalized for observation. These were treated as 14 injuries for the purposes of this study.

It is interesting to note that each of these spills had a different cause. Two were caused by some form of third party damage, while the third was caused by a material defect.

The number of incidents resulting in injuries and fatalities was too small to draw any meaningful conclusions. However, it should be noted that all injuries and fatalities occurred on petroleum product pipelines; crude line incidents did not result in any injuries or fatalities during the study period.

The present regulations are basically the same for product and crude pipelines. However, although a limited sample, this data indicated that the risks to human life were likely greater for product pipelines. As a result, there may be justification for having some differences between crude and product pipeline regulations. On the other hand, both crude and product pipeline incidents resulted in similar environmental concerns.

As mentioned previously, *all* injuries, regardless of severity, were included in these data. For instance, the 1986 Tustin incident resulted in 14 injuries which did not meet the Department of Transportation injury reporting criteria. Deleting these injuries alone would have reduced the resulting injury rate for this study by more than one-third. The reader must keep the injury criteria used in this study in mind; otherwise, the public injury risk may be over-exaggerated. Unfortunately, sufficient data was not available to sort the injuries incurred during the study period by severity.

4.26 Multiple Regression Analyses

As mentioned briefly in preceding sections, multinomial logit regressions were performed. These analyses predicted the probability of a pipeline rupture considering selected variables. The variables used were those that appeared to influence the incident rates observed in previous analyses, provided data was available to perform the analyses.

The first regressions included the following variables:

- total pipeline length,
- year of pipe construction,
- normal operating temperature,
- normal operating pressure,
- normal operating flow rate,
- length within 500 feet of a rail line,
- length of inspection piggable pipeline,
- dummy variable indicating interstate or intrastate pipeline, and
- dummy variable indicating common carrier or non-common carrier pipeline.

A polytimous dependent variable was used with three outcomes possible: 0) no leak; 1) leak due to external corrosion; and 2) leak due to other causes. For purposes of comparison, two models were used in the analyses. The first, was a logit regression which used a dependent variable with all leaks combined. The second was a multinomial logit regression using the polytimous dependent variable that breaks down ruptures by cause. The second model was defined as such because the majority of the leaks were caused by external corrosion. As a result, the factors affecting the external corrosion leaks may have been different than those affecting leaks caused by other sources. The regression used outcome 0, no leak, as the point of departure. The probability of outcome 1 or 2, or both combined, was predicted, therefore, relative to the probability of outcome 0.

From the coefficients and significance levels provided, we observed that the probability of a leak due to external corrosion was differentially affected by the independent variables in comparison to the probability of a leak due to other causes. Thus the polytimous logit model was better suited to predict the probability of a leak.

The probability of a leak occurring due to external corrosion was affected positively by normal operating temperature and total length of pipeline. These correlations were statistically significant at the 0.000 level. The year of pipe construction was inversely related to the probability of a leak and was also highly significant at the 0.002 level. Specifically, as pipe age increased, as normal operating temperature increased and the total pipeline length increased, external corrosion leaks were more probable holding all else constant. Operating pressure and proximity to a rail line showed no statistical relationship to the probability of a leak due to external corrosion.

In contrast, the relationship between normal operating temperature and the probability of a leak occurring due to causes other than external corrosion was not statistically significant. Coincidentally, increased normal operating flow raised the probability of a leak occurring from other causes, while not affecting external corrosion leaks. Additionally, common carrier status increased the probability of a leak from other causes, but did not affect the probability of an external corrosion incident. Year of construction had the greatest effect on the probability of all leaks. The total length of pipeline was directly and significantly related to the probability of a leak occurring. There was no statistical relationship between the length of line near a rail line and the probability of an incident from any cause.